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Attorney for Rob Simpson and Helping Hand Tools

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA

1516 NINTH STREET, SACRAMENTO, CA 95814

1-800-822-6228 – WWW.ENERGY.CA.GOV

APPLICATION FOR CERTIFICATION	**Docket No. 11-AFC-01**

Rob Simpson's and Helping Hand Tools Supplement Comments to the PMPD
Part 4a of 5

The following 11 emails and attachments were submitted to all parties on or about September 5, 2012. Mr. Simpson and Helping Hand Tools submits this document for public comment.

Respectfully submitted.

Date: September 11, 2012

/s/ Gretel Smith , Esq.

Gretel Smith, Esq.

Attorney for Helping Hand Tools &

Rob Simpson

Email 6 of 11

Email 6 of 11

From: <rob@redwoodrob.com>
Date: Wed, Sep 5, 2012 at 9:06 AM
Subject: Pio Pico PMPD comments Rob Simpson 6
To: "Scott, Diane@Energy" <Diane.Scott@energy.ca.gov>, "djenkins@apexpowergroup.com" <djenkins@apexpowergroup.com>, "MFitzgerald@sierraresearch.com" <MFitzgerald@sierraresearch.com>, "jamckinsey@stoel.com" <jamckinsey@stoel.com>, "mafoster@stoel.com" <mafoster@stoel.com>, "e-recipient@caiso.com" <e-recipient@caiso.com>, "rob@redwoodrob.com" <rob@redwoodrob.com>, "Gretel.smith79@gmail.com" <Gretel.smith79@gmail.com>, "swilliams@scmv.com" <swilliams@scmv.com>, "Peterman, Carla@Energy" <Carla.Peterman@energy.ca.gov>, "Douglas, Karen@Energy" <Karen.Douglas@energy.ca.gov>, "Renaud, Raoul@Energy" <Raoul.Renaud@energy.ca.gov>, "Bartridge, Jim@Energy" <Jim.Bartridge@energy.ca.gov>, "Lemei, Galen@Energy" <Galen.Lemei@energy.ca.gov>, "Nelson, Jennifer@Energy" <Jennifer.Nelson@energy.ca.gov>, "Solorio, Eric@Energy" <Eric.Solorio@energy.ca.gov>, "kevinw.bell@energy.ca.gov" <kevinw.bell@energy.ca.gov>, "Allen, Eileen@Energy" <Eileen.Allen@energy.ca.gov>, Energy - Public Adviser's Office <PublicAdviser@energy.ca.gov>

Docket Number 11-AFC-01

Rob Simpson
Director
Helping Hand Tools (2HT)
1901 First Avenue, Ste. 219
San Diego, CA 92101
Rob@redwoodrob.com

-------- Original Message --------
Subject: Pio Pico PSD comments 4
From: <rob@redwoodrob.com>
Date: Wed, July 18, 2012 1:19 am
To: Kohn.Roger@epa.gov

Attached please find my initial Pio Pico PSD comments Pio Pico PSD comments

Rob Simpson
Executive Director
Helping Hand Tools
27126 Grandview Avenue
Hayward CA. 94542
Rob@redwoodrob.com

PDOC.Rob.Comments.doc

58K View Download

PDOC.Rob.Comments.pdf
169K View Download

20-may-08_Smart Energy 2020_2nd printing_complete.pdf
3917K View Download

Attachment 1 of 2 to
Email 6 of 11

January 18, 2012

Steven Moore

San Diego Air Pollution Control District

10124 Old Grove Road

San Diego, CA 92131.

Re: Preliminary Determination of Compliance for proposed development of the Pio Pico Energy Center (District Application No. APCD2010-APP-001251)

Dear Mr. Moore:

I am writing to request an extension of the Public Comment period and a Public Hearing on the proposed Preliminary Determination of Compliance for Pio Pico Energy Center. I submit the following only as tentative comments subject to modification upon the extension of the comment period and after the public hearing. Please also provide me an index of the administrative record for this action, and electronic copies of all public records contained therein and all communications regarding the action.

The comment period should be extended because I, and other members of the public, would like to get answers from the District that I have repeatedly requested, in writing, regarding the proposed action. I began requesting a copy of the PDOC from the District on December 26, 2011 (attached) Please consider all my emails regarding this project as part of my public comment. After repeated requests I finally received a copy of the PDOC from the District 15 days later on January 9, 2012, leaving only 9 days until expiration of the comment period. On January 11, 2012 I requested information about the Emission Reduction Credits proposed as offsets for the project. Despite repeated requests I have not received the information. The public comment period should remain open until at least 30 days after the District chooses to disclose the ERC information that I requested or at least 30 days after the District chose to provide a copy of the PDOC to me.

My request for a public hearing is based upon the contentions contained in my comments and my desire to ask questions and allow other members of the public to participate before the District regarding this project.

Please consider all comments attributed to me, whether phrased as statement or questions, as objections to issuance of a Final Determination of Compliance (FDOC), contentions that the District clearly erred, and requests for changes to the determination.

1. The project description is insufficient

The project appears to be a modification of the adjacent generating facility. Please identify what infrastructure the projects share, any business relationships between the project owners, operators or investors. Please identify what entity controls the generation or output from each facility. Is it the California Independent System Operator (CAISO)? The local utility? The Public Utilities commission (PUC)? California Energy Commission (CEC) or some other entity.

The CEC stated; "the Energy Commission found the AFC data adequate on April 20, 2011 On June 8, 2011, the Applicant filed a Project Refinement document On October 6, 2011, Staff informed the Committee that Applicant is revising the project" The District should consider the refinement and revision in its deliberations.

The PDOC states; "The PPEC three CTGs will be the first emission units operating at this stationary source. Therefore, the Contemporaneous Emission increase for the PPEC stationary source is the same as; the project potential to emit" The District should consider this project to be a modification of the existing facility.

2. Impact on local community have not been fully addressed

The location appears to be between the Mexican border and a couple of prisons, including juvenile and immigrant detention prisons. Has the District conducted any outreach or provided any public notice to the Mexican Government or people, or the prisons or prison populations? How far are the prisons from the facilities? Does the District have a duty to provide notice to any of the above? Can the prison population be considered an environmental Justice community? Might they have different stressors? The District should conduct a health screening of the inmates. One of the prisons apparently has an air monitoring station on it. Has the District studied the fact that the impact to prisoners (most certainly an EJ community) may be different than normal resident or worker impacts, since they may not leave. What is the impact on the prisons and country of Mexico? Has the District considered the potential of the project to use LNG from the new Mexican port?

3. District has not followed its own rules

The PDOC states:

> The District is currently not delegated to implement federal PSD by EPA nor does it have a PSD rule that has been approved by EPA. Hence, PSD permitting for federal PSD is solely the responsibility of EPA at the current time. The District's New Source Review

(NSR) rules do contain provisions for PSD that the District implements locally. The proposed project's compliance with these provisions is evaluated in the PDOC in accordance with District Rules and Regulations. it is worth noting that, although the District PSD provisions reflect many elements of federal PSD, there are some differences. In particular, the District currently has no authority in its Rules and Regulations to address greenhouse gases CGHGs).

The Air District is acting like their PSD rules do not apply as they are not delegated to handle GHG PSD. I contend that this is a PSD source and the District should follow its PSD rules. What would the District have done differently if they had acknowledged responsibility under the PSD provisions of the Clean Air Act (CAA) and State Implementation Plan (SIP) and District rules? How do the District rules differ from the SIP or CAA? Under which set of rules should the District and public consider this action?

The PDOC states; "Rule 20.3(d)(4) - Public Notice and Comment For any project that is subject to the AQIA requirements of Rule 20.3(d)(2), these provisions require that the District publish a notice of the proposed action in at least one newspaper of general circulation in San Diego County as well as send notices and specified documents to the EPA and ARB. Because the project is not subject to Rule 20.3(d)(3) the additional notification requirements of Rule 20.3(d)(3)(iii) are not applicable." I contend that the project is subject to these rules including a AQIA including PM2.5. The District rules do not appear to comport with the CAA particularly for PM2.5 and GHG.

4. A PSD permit is required for all emissions

It appears that the applicant wishes to consider the project a simple cycle generator so that the PSD thresholds are 250 tons. The PDOC states:

> Although the PPEC is a fossil fuel fired electrical generating plant with a heat input rating greater than 250 MMBtulhr, it is not a steam generating plant. Therefore PSD Stationary Source status is defined by an aggregate potential to emit one or more air contaminants in amounts equal to or greater than any of the following emission rates under District rules and under federal rules except for the recently promulgated federal PSD requirements for greenhouse gases.

The District should consider the possibility that the applicant will modify the facility to a more efficient combined cycle facility as others have and effectively evade PSD review. This could be a sham permit.

The PDOC states "The PPEC will utilize three GE LMS 100 intercooled natural gas fired combustion turbine generators (CTGs). each equipped with water injection...Section /60.4335(b) requires turbines using water injection or steam injection to install, calibrate, maintain and operate a continuous emission monitoring system (CEMS)" I contend that the water injection is "producing steam by heat transfer" 40 CFR 60.41 and therefore the District erred in its PSD calculations.

The PDOC states; "The combustion turbines are also equipped with evaporative coolers that can be used to cool the inlet air to each turbine to increase power during periods of high ambient temperature." (PDOC) the evaporative coolers are also; "producing steam by heat transfer"

A partial dry-cooling system (PDCS), which is a closed-looped two- stage cooling system *is* used for the plant. In this system, heat rejected from the turbine compressor and the lube oil system is cooled using ambient air in a dry-cooling system, followed by a closed-loop evaporative fluid cooler for additional cooling. Recycled water supplied by the Otay Water District will be used for cooling system makeup, CTG water injection, and CTG inlet air evaporative cooler makeup. Makeup water for the cooling water system will be stored in a 750,000-gallon raw water storage tank. This raw water will be treated with water-conditioning chemicals to minimize corrosion," This also appears to have the effect of "producing steam by heat transfer".

The PDOC states; "EPA would currently be the agency to issue a PSD permit, with no effect on the validity of the District's Final Determination of Compliance (FDOC)." Please identify the legal basis for this conclusion. I contend that the EPA PSD considerations could have an effect.

5. The alternatives analysis and consideration of mitigation strategies is insufficient

"The PDOC states; "Rule 20.3(e)(2) - Alternative Siting and Alternatives Analysis The Applicant has provided an analysis of various alternatives to the project. This analysis included a No Project alternative, alternative sites, and alternative technologies. Since all of San Diego County is currently classified as non-attainment for ozone, an alternative location within San Diego would not avoid the project being located in a non-attainment area." The project is not needed and the District should conduct a no project alternative analysis. I can provide additional basis for this contention if the District extends the comment period.

The District should require combined cycle operation and locating the facility in location(s) that could benefit by combined heat and power opportunities. Perhaps at the prisons.

The District should consider solar and wind assistance and alternatives. The District should consider battery or other storage. The District should require emission capture and storage also known as Carbon Capture and Storage (CCS) but would sequester other emissions as well. The District should consider wet scrubbers with algae based aqueous sequestration.

The District should consider mitigations, which may benefit the affected community, besides ERCs; Natural gas powered school buses, energy conservation retrofits, perhaps respirators for prisoners or other prison considerations, etc. What is the value or cost of the ERCs proposed for the project?

6. Issues with evaporative cooling

The PDOC states; "EVAPORATIVE COOLING The proposed GE LMS 100 turbines have inlet air filters located upstream of the evaporative coolers. The evaporative cooler is turned on only during operation in hot weather. The particulate emission factor of 5.5 lbs/hr provided by the turbine vendor includes anticipated particulate matter from the evaporative cooler parameters since the water supply is expected to comply with the vendor's recommended water quality standards. Therefore, no further particulate emissions from the evaporative cooler are included in the emission calculation." How did the District determine the quality of the water? The District should consider Additional filtration or other methods which could increase the water quality thereby reducing PM emissions. The PDOC states; "Since the projects permitted with the lower drift rate of 0.0005% have not been in operation, this drift rate is not considered achievable in practice and is not considered BACT. Based on this information, the District has determined that the drift rate of 0.001 % is BACT for PPEC cooling tower." The District erred in this conclusion; BACT was established at the lower rate and the District should adopt it.

The PDOC states; "This raw water will be treated with water-conditioning chemicals to minimize corrosion, bio-fouling, and formation of mineral scale." Please identify the chemicals used, their effect on air quality and any environmentally superior options. The District should study and disclose if the use of recycled water can cause legionnaires disease or other negative effects.

7. Basic information is lacking

The PDOC states; "The Applicant estimates that there will be up to 500 typical startups per turbine per year and up to 500 typical shutdowns per turbine per year. Maximum annual emissions are calculated based on 500 hours with a startup, 500 hours with a shutdown, and 3,335 hours per year at full-load operation under average conditions for all three CTGs." *and* "Maximum daily emissions from each combustion turbine are calculated based on the assumption that each turbine operates up to 24 hours per day, of which 4 hours include a startup, 4 hours include a shutdown, and 16 hours for maximum normal operation at peak average ambient temperature" While these two statements appear to contradict each other they point out that the District failed to include limits for the number of start ups. The FDOC should include a limit of the number of start ups.

The PDOC states; ""Project emissions of NOx, CO, sulfur oxides (SOx, VOCs, particulate matter less than or equal to 10 microns in diameter (PM 10), and particulate matter less than or equal to 2.5 microns in diameter (PM2.5) were estimated based on data supplied by the turbine manufacturer and emission limits in the PDOC permit conditions. The startup and shutdown emission rates were provided by the turbine manufacturer." Please identify if the turbine manufacturer guaranteed its data and rates.

8. Additional issues not addressed in the PDOC

The PDOC States; "[Note that District Rule 20.1 does not explicitly address PM2.5 nor does it address particulate matter of all sizes (PM). However, PM2.5 is addressed as subset of PM 10]."

This does not comport with the CAA. Who does the District expect to ensure compliance with the PM2.5 provisions of the CAA?

The ERC's proposed for this project are inadequate, as the District has declined to provide information about them.

The PDOC states; "Rule 51- Nuisance This rule prohibits the discharge of air contaminants that cause or have a tendency to cause injury, nuisance, annoyance to people and/or the public or damage to any business or property. No nuisance or complaints are expected from this type of equipment." Please identify the basis for this statement. I contend that the project would be a nuisance and the District should give this adequate consideration. The District should study the localized effects of GHG's They form a sort of dome around emitters that concentrate other emissions in the area. Please consider the Jacobson effect (attached)

What sources were considered in the background for modeling? Was the adjacent facility included? Roadways? Other sources. Any emissions form Mexico? Are there other sources or proposed sources in Mexico or USA that could be considered?

Please demonstrate the effects of nitrogen deposition from the project(s).

9. Procedural and public participation issues

Please identify the appeal opportunities if the District issues an FDOC for this project. Does the District delegate its authority under the CAA or SIP to the CEC or others? Can the FDOC be appealed to the District Hearing Board or CARB. When would an appeal be ripe? Upon issue of the FDOC or at another time? Does the District issue an ATC or does the CEC. Is the MOU; "APPROVED .*ARB-CEC* JOINT POLICY STATEMENT OF COMPLIANCE WITH AIR QUALITY LAWS BY NEW POWER PLANTS" (attached) in force at this time? if not what " fully preserves the integrity of California's air quality program" in its stead. My experience is that the interaction between the agencies violates due process in the void of this MOU as there appears to be no venue to appeal an FDOC.

10. <u>BACT NOX</u>

The Districts BACT analysis for NOx does not meet the requirement for a BACT/LAER analysis. A proper BACT analysis for this project would first consider the possible combustion controls and then analyze post combustion controls. The districts BACT analysis does not consider any combustion controls that could be utilized for the PPEC. Available combustion control technologies for reducing NOx emissions from the combustion turbines are;

Steam/Water Injection: Steam or water injection was one of the first NOx control techniques utilized on gas turbines. Water or steam is injected into the combustion zone to act as a heat sink, lowering the peak flame temperature and thus lowering the quantity of thermal NOx formed. The injected water or steam exits the turbine as part of the exhaust. The lower peak flame temperature can also reduce combustion efficiency and prevent complete combustion, however, and so carbon monoxide and POC emissions can increase as water/steam-to-fuel ratios increase. In addition, the injected steam or water may cause flame instability and can cause the flame to quench (go out). Water/steam injection in the combustion turbines can achieve NOx emissions as low as 25 ppm @ 15% O2.

Dry Low-NOx Combustors (DLE): Another technology that can control NOx without water/steam injection is Dry Low-NOx combustion technology. Dry Low-NOx Combustors reduce the formation of thermal NOx through (1) "lean combustion" that uses excess air to reduce the primary combustion temperature; (2) reduced combustor residence time to limit exposure in a high temperature environment; (3) "lean premixed combustion" that reduces the peak flame temperature by mixing fuel and air in an initial stage to produce a lean and uniform fuel/air mixture that is delivered to a secondary stage where combustion takes place; and/or (4) two-stage rich/lean combustion using a primary fuel-rich combustion stage to limit the amount of oxygen available to combine with nitrogen and then a secondary lean burn-stage to complete combustion in a cooler environment. Dry Low-NOx combustors can achieve NOx emissions as low as 9 ppm.

Catalytic Combustors: Catalytic combustors, marketed under trade names such as XONON™, use a catalyst to allow the combustion reaction to take place with a lower peak flame temperature in order to reduce thermal NOx formation. XONON™ uses a flameless catalytic combustion module followed by completion of combustion (at lower temperatures) downstream of the catalyst. Catalytic combustors such as XONON™ have not been demonstrated on Aero-derivative simple-cycle gas turbines such as the GE LM 100 Class. The technology has been successfully demonstrated in a 1.5-megawatt simple-cycle pilot facility, and it is commercially available for turbines rated up to 10 megawatts, but it is not currently available for turbines of the size proposed for the PPEC.

The applicant has chosen water injection as the post combustion control. Water injection will increase particulate matter emissions from the project by as much as 10%. This is a collateral impact that must be analyzed. Technological alternatives must be considered. For example the LM-100 turbines are now available with DLE. DLE would eliminate the particulate matter emissions from the use of demineralized water in the combustion control process. The LM-100 with DLE would lower GHG emissions as it has a lower heat rate. The DLE technology will eliminate over half of the water needed for the project. The BACT analysis must discuss the various control technologies rank their feasibility and effectiveness and select the proper control. The PDOC fails to do so.

11. Post Combustion Controls

After considering the combustion controls the BACT analysis must consider post combustion controls and asses their technological availability, cost effectiveness, and any other collateral impacts associated with the post combustion technology. For example the applicant has chosen SCR as the post combustion control for NOx. The BACT/LAER analysis should discuss the collateral impacts of SCR and the other possible post combustion controls. SCR has several collateral impacts. SCR utilizes ammonia for NOx control. The first is the formation of secondary particulate matter from the ammonia slip is one collateral impact. The transportation and storage of the ammonia is also a collateral impact form the use of SCR. The ammonia used in the SCR can alos contribute to nitrogeon deposition that can harm plant and animal life. All of these impacts mut be discussed and analyzed in a proper top down BACT analysis. .

12. BACT for VOC

The PDOC states that the District consulted the EPA BACT / LAER Clearinghouse, other air district decisions and BACT Guidelines, and ARB for recent BACT/LAER determinations.[6] Based on the information and considerations, the District determined that BACT for the PPEC combustion turbines is a 2.0 ppmvd VOC limit, measured as methane at 15% O2 over a one-hour averaging period for normal operation with exclusions for startups and shutdowns.[7]

The BAAQMD conducted a BACT analysis for the recently approved Mariposa Energy Center.[8] After a cost effective analysis the District determined that BACT for the simple-cycle gas turbines for VOC is the use of good combustion practice and abatement with an oxidation catalyst to achieve a permit limit for each gas turbine of 0.616 lb per hour or 0.00127 lb/MMbtu, which is equivalent to 1 ppm POC, 1-hr average.[9] As the District is in non attainment for ozone the District must conduct a cost effectiveness analysis and adopt the current BACT standard for VOV of 1ppm averaged over 1 hour.

13. PM-10 BACT

For the CPV sentinel Project which utilizes the LM-100 turbine GE has provided vendor guarantees that LM-100 can achieve a 5 pound per hour limit. GE revised the PM10 emissions

[6] VOC BACT Determination PDOC Page 18
[7] VOC BACT Determination Page 19
[8] http://www.energy.ca.gov/sitingcases/mariposa/documents/index.html
[9] Mariposa PDOC Page 51

from the CTG to 5 lb/hr instead of 6 lb/hr, see guarantee e-mail dated 10/21/09.[10] The 5 pound per hour limit represents BACT for the LM-100 for PM-10 emissions.

14. PM BACT Cooling Tower

BACT for the cooling tower is a drift rate of 0.0005%. This BACT has existed for many years and represents BACT for cooling tower emissions from the PPEC.

15. Compliance with the Federal 1 Hour NO2 Standard

The 1 hour Federal NO2 analysis fails to satisfy the USEPA's requirements for the placement of NO2 monitors, which states: *In urban areas, monitors are required near major roads as well as in other locations where maximum concentrations are expected.* Major roadways are defined as those with at least 250,000 annual average daily traffic and monitors for this exposure condition must be located within 50 meters of the monitoring station.

Thank you,

Rob Simpson

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[10] CPV Sentinel Addendum to the FDOC March 2, 2010 http://www.energy.ca.gov/sitingcases/sentinel/documents/others/2010-03-02_South_Coast_AQMD_Addendum_to_DOC_TN-55739.PDF Page 11

Attachment 2 of 2 to

Email 6 of 11

San Diego
Smart Energy 2020

THE 21ST CENTURY ALTERNATIVE

PREPARED BY

E-Tech International, Santa Fe, New Mexico

AUTHOR

Bill Powers, P.E.

October 2007

Cover photo: San Diego Education Center equipped with a high efficiency cool roof and 100 kW of rooftop solar photovoltaic panels (photo provided by Solar Integrated Technologies)

San Diego Smart Energy 2020
– The 21st Century Alternative –

Prepared by:

E-Tech International
Santa Fe, New Mexico

Author: Bill Powers, P.E.

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The author would like to acknowledge the numerous informal reviewers as well as the following individuals for reviewing the draft document and providing comments:

Henry Abarbanel:	Co-Chair, San Diego Association of Governments Regional Energy Working Group
Scott Anders:	Director, Energy Policy Initiatives Center, University of San Diego School of Law
Richard Caputo:	President, San Diego Renewable Energy Society
Don Wood:	Senior Policy Advisor, Pacific Energy and Policy Center, La Mesa

About the author:

Bill Powers, P.E., is an expert on regional power provision, with extensive knowledge and experience in the fields of energy and mechanical engineering, air monitoring and control equipment, and pollution and public health. He is internationally renowned for his work in the energy field, providing expert testimony and analysis, project management, strategic planning, and equipment testing and monitoring for private energy project developers throughout the world, including the United States, Mexico, Peru, Venezuela, Panama, and Chile.

Mr. Powers has served as the U.S. co-chair of the San Diego-Tijuana EPA/SEMARNAT Border 2012 Air Work Group, a federal initiative which develops programs to reduce air pollution along the international border. He is also co-chair of the Border Power Plant Working Group, a binational organization which advocates for sustainable energy projects in the border region. In addition, he is a member of San Diego Association of Governments Regional Energy Working Group.

Mr. Powers has authored numerous technical reports on a variety of energy-related topics, including gas turbine air emission controls, power plant cooling systems, integrating strategic energy and environmental planning in the California – Baja California border region, and use of integrated gasification combined cycle power generation to facilitate carbon dioxide capture and sequestration in Midwestern coal-burning states. He received his Bachelor of Science in Mechanical Engineering from Duke University and Masters of Public Health – Environmental Sciences from the University of North Carolina. Mr. Powers has been a registered professional engineer in California since 1986.

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Figures

Attachments

1. Executive Summary

The San Diego region is poised on the brink of a new energy future, and the path it charts now will determine in large part the success of its people, its economy, and its ability to provide a cleaner, more secure energy supply for generations to come.

San Diego Smart Energy 2020 paves the way for a shift from reliance on fossil fuels and imported power to an array of local solutions that include energy efficiency measures with emphasis on high efficiency air conditioning systems; common-sense weatherization and conservation; the proven technology of solar photovoltaic (PV) panels, for large commercial use as well as on homes; small, highly efficient natural gas-fired power plants that generate both power and heating/cooling; adoption of smart grid procedures that improve the efficiency of the grid by monitoring and controlling the flow of electricity on a continuous basis; and the widespread institution of green building design principles.

San Diego Smart Energy 2020, the strategic energy plan for San Diego County described in this report, provides a working blueprint of realistic methods to reduce greenhouse gases from power generation by 50 percent over current levels by 2020 while increasing the total electricity supply from renewable energy resources and maximizing locally generated power. The plan is economically feasible for residents and businesses alike.

Finding 1: Climate Change Must Drive Strategic Energy Planning

The *Global Warming Solutions Act* (AB 32, September 2006) commits California to reducing greenhouse gases by 25 percent to 1990 levels by 2020, and by 80 percent by 2050.

San Diego Gas & Electric (SDG&E) is currently projecting a 20 percent reduction in greenhouse gas emissions over the next decade as part of its strategic plan. This reduction will principally be achieved by meeting the state mandate of 20 percent renewable energy generation by 2010. However, SDG&E’s parent company, Sempra Energy, will begin shipping liquefied natural gas north through SDG&E’s pipeline system from its Baja California liquefied natural gas terminal in 2009. The lifecycle greenhouse gas burden of liquefied natural gas, including processing, liquefying, transport, and regasification, is approximately 25 percent greater than that of the domestic natural gas SDG&E is currently supplying. The SDG&E greenhouse gas projection, provided in SDG&E’s 2007-2016 Long-Term Procurement Plan, does not take into account the generation of additional greenhouse gases associated with the conversion from domestic natural gas to imported liquefied natural gas. This conversion will nullify the greenhouse gas reductions projected by SDG&E over the next decade.

A much more significant shift from fossil fuel to renewable energy sources will be required if the San Diego region is to reduce its greenhouse gas emissions at the maximum rate that is cost-effectively achievable.

Finding 2: A Secure Energy Future Requires an Increase in Local Power Generation and a Decreased Dependence on Natural Gas

Approximately two-thirds of the electric power used in the San Diego region is currently generated by coal-fired (12 percent) and natural gas-fired (53 percent) combustion sources. The power is imported along existing transmission lines as well as being generated by local power plants.

Virtually all local power generation sources burn natural gas. The price of natural gas has nearly tripled since 2002, and remains highly volatile. The high price of natural gas has made renewable energy sources more-cost effective when compared to natural gas-fired power generation sources.

San Diego's political, business, environmental, and community leaders have a history of innovative thinking in planning for the region's energy future. In 2003, the San Diego Association of Governments (SANDAG) adopted the *San Diego Regional Energy Strategy 2030.* The document places strong emphasize on expanded local power generation, including both renewable energy sources and highly efficient combined heat and power (CHP) projects for large businesses and government facilities. Enhanced energy efficiency and energy conservation efforts, and modernization of the region's natural gas-fired power plants to reduce natural gas consumption, are also key elements of *San Diego Regional Energy Strategy 2030.*

Finding 3: A San Diego Energy Future Focused on Photovoltaics Is Cost-Competitive

In 2006, Governor Schwarzenegger signed into law Senate Bill 1, an amended version of the "million solar roofs" California Solar Initiative, to provide incentives for commercial PV applications up to one megawatt (MW) as well as residential systems. The amended California Solar Initiative will rely on $3.35 billion in incentives to add 3,000 MW of rooftop PV in California by 2017. It is anticipated that approximately 300 MW of PV will be added in the San Diego area as a result of this solar legislation.

A core element of *San Diego Smart Energy 2020* is adding over 2,000 MW of PV locally by 2020. This ambitious solar program, the *San Diego Solar Initiative,* will use an incentive structure similar to that of the California Solar Initiative. Power generated from PV systems, when combined with sufficient solar incentives, current federal tax credits, and current accelerated depreciation, is less expensive than conventional power purchased directly from the utility. For example, the City of San Diego pays $0.12 per kilowatt-hour (kWh) to a third party provider for the power generated by the 965 kilowatt PV array at the City's Alvarado Water Treatment Plant under a long-term power purchase agreement. In contrast, the City pays approximately $0.17 per kWh to SDG&E for conventional purchased power.

The PV industry expects the capital cost of PV to drop 40 percent by 2010 due to an increase in manufacturing capacity worldwide. SDG&E will install electronic "smart" electric meters throughout the San Diego area by 2011. PV systems generate power during the day when electricity prices are highest. These smart meters will precisely track when PV systems are sending power to the grid. This in turn will enable fair compensation for the high value electricity being produced, further enhancing the economics of PV power generation.

Finding 4: Current State Policies Do Not Provide Utilities with Incentives to Prioritize Energy Efficiency, Renewable Energy, and Distributed Generation

California utilities earn a fixed profit based on the value of the property the utility owns. Examples of such property are utility-owned power plants, transmission and distribution lines, and electric and gas meters. The more a utility invests in these types of infrastructure, the more money is earned.

However, in 2003, the California Public Utilities Commission (CPUC) and the California Energy Commission adopted the *Energy Action Plan* and its associated power generation priorities or "loading order." The *Energy Action Plan* provides a roadmap for meeting California's future energy needs. The top priority listed in the *Plan* is energy efficiency to minimize increases in electricity and natural gas demand. Demand response, or reducing electricity demand during periods of peak usage, is next, followed by renewable energy resources and clean natural gas-fired CHP projects. Conventional power plant resources are identified as the last generation priority, to be considered only after maximum development of energy efficiency, renewable energy, and distributed generation has been realized.

A major hurdle to implementing the *Energy Action Plan* is the traditional utility revenue system. This system does not provide California utilities with a financial incentive to invest in energy efficiency, renewable resources, or distributed generation. However, a September 2007 ruling by the CPUC established incentives and penalties to motivate the utilities to pursue energy efficiency more aggressively. This is an important first step toward adapting the utility revenue system to reflect the priorities of the loading order.

Finding 5: Quality of Life in San Diego Requires New Thinking for Energy Supply – San Diego Smart Energy 2020

The primary objective of the energy strategy described in this report is to achieve a 50 percent reduction in greenhouse gas emissions from power generation sources by 2020. *San Diego Smart Energy 2020* is designed to accelerate local, smart distributed generation, with an emphasis on energy efficiency, commercial PV systems, and CHP installations. Implementation of *Smart Energy 2020* will: 1) maximize greenhouse gas reduction, 2) enhance energy security by minimizing dependence on natural gas for power generation, and 3) greatly expand local clean peak generation capacity to minimize reliance on power imports during periods of high demand when competition for these power imports is greatest.

San Diego Smart Energy 2020 calls for the addition of 2,040 MW of rooftop solar, with an emphasis on large commercial installations. It also includes the addition of 700 MW of clean distributed generation from CHP sources. Under *Smart Energy 2020*, renewable energy resources will provide 50 percent of San Diego County's energy demand in 2020. *Smart Energy 2020* is outlined in Table 1-1. *The San Diego Solar Initiative* is a cornerstone of the *Smart Energy 2020* strategy. The *Initiative* will be funded by a $1.5 billion PV incentive budget. The 2,040 MW of PV capacity built under the *Initiative* will be equipped with sufficient battery storage to allow full use of this capacity during peak demand periods.

A more limited *San Diego Smart Energy 2020* with a reduced PV incentive budget of $700 million is outlined in Table 1-2. Under current cost allocation policy, SDG&E customers will be charged only 10 percent, or approximately $700 million, of the $7 billion lifecycle cost of the proposed Sunrise Powerlink (SPL) transmission project. A $700 million *San Diego Solar Initiative* will provide for 920 MW of PV capacity by 2020 equipped with sufficient battery storage for reliable peaking power duty. Under this more limited approach, renewable energy resources will provide 36 percent of San Diego County's energy demand in 2020.

San Diego Smart Energy 2020 increases local peak generation in 2020 by 2,670 MW beyond the level of new local peak generation achieved in SDG&E's long-term plan. The limited version of *Smart Energy 2020*, as outlined in Table 1-2, will increase local peak generation in 2020 by 1,550 MW beyond the new local peak generation achieved in the SDG&E plan. In comparison, the proposed SPL transmission line would add 1,000 MW of power import capability. The greatly increased amount of local peak power generation capacity installed under either *Smart Energy 2020* scenario will eliminate the need to build new transmission to provide reliability during periods of peak power demand.

New residential and commercial buildings would incorporate state-of-the-art green building principles and sufficient rooftop solar to address expected electric energy consumption under *San Diego Smart Energy 2020*. The objective is net zero energy consumption in new construction.

Recommendation: Implement *San Diego Smart Energy 2020*

Step 1: Realign SDG&E financial incentives to match *Energy Action Plan* priorities

Step 2: Achieve absolute reduction of 20 percent in annual energy consumption by 2020

Step 3: Achieve absolute reduction of 25 percent in peak demand by 2020

Step 4: Achieve 50 percent reduction in greenhouse gas emissions from power generation by 2020 through use of local PV and CHP distributed generation

Step 5: Prioritize modernization of the 1950s-vintage electrical distribution system to maximize potential benefits of smart grid

Step 6: Assure new construction in San Diego incorporates state-of-the-art green building principles and sufficient rooftop solar to meet own electricity demand

Each *San Diego Smart Energy 2020* scenario is compared side-by-side with the SDG&E 2016 strategic plan in Tables 1-1 and 1-2. The targets in Tables 1-1 and 1-2 are described in terms of annual electric energy usage and peak power demand. Annual energy usage is analogous to the total gallons of fuel used by an automobile over the course of a year. Peak power demand is analogous to the maximum horsepower required of the automobile when it is fully loaded and must maintain a high rate of speed while driving up a hill. Electricity planning in California is largely guided by peak power demand.

Table 1-1. Comparison of San Diego Smart Energy 2020 ($1.5 billion incentives budget) and SDG&E Strategic Plan

	San Diego Smart Energy 2020 – $1.5 Billion Solar Incentive Expenditure			**SDG&E Strategic Plan – 2016 $7 Billion Sunrise Powerlink Expenditure** ($700 million allocated to SDG&E customers)		
Element	Action	Demand/ supply (GWh-yr)	Electricity cost impact	Action	Demand/ supply (GWh-yr)	Electricity cost impact
2003 baseline annual energy demand:		20,000			20,000	
1. Energy Efficiency (EE) /Demand Reduction (DR)	Reduce energy demand 20%, 4,000 GWh, compared to 2003 baseline of ~20,000 GWh thru EE. Maximize DR thru cooling system EE upgrades and "smart" meters to reduce peak 25% from 2007 peak of 4,636 MW to 3,500 MW.	(4,000)	neutral	Energy demand increases 4,679 GWh relative to 20,000 GWh baseline. Peak demand increases 560 MW to 5,060 MW from 4,500 MW baseline.	4,679	neutral
2020 annual energy demand:		16,000		2016 SDG&E:	24,679	
2020 sources of energy supply – San Diego Smart Energy 2020:				2016 SDG&E sources of energy:		
2.Renewable Energy	a. SB 107 - 20% renewable energy by 2010. b. Million solar roofs – 300 MW by 2017. c. San Diego Solar Initiative – 2,040 MW w/ battery storage for peaking duty at rated capacity, 3-6 pm (2,265 MW w/o storage).	3,500 600 3,900	existing existing $1.5 billion (lifecycle cost, 2007 dollars)	a. SB 107 - adjusted to 2016. b. 300 MW by 2017. c. None.	3,800 600 0	existing existing none
3. Combined heat and power	a. Existing – 350 MW b. New – 700 MW	2,500 5,000	existing neutral	a. Existing – 350 MW b. New – 40 MW	1,800 300	existing neutral
4. Conventional gas-fired power plants	a. Two existing local 550 MW combined-cycles (CC): nighttime and cloudy days. b. Existing local simple cycle peakers, 500 to 700 MW capacity: as needed to meet peak.	500 [net]	existing/ neutral existing/ neutral	a. Local and imported CC power, assume 40/60 split. b. Simple cycle peakers: as needed to meet peak.	14,729	power from existing generation
5. Nuclear and large hydro-electric imports.	Not necessary to implement strategy.	0	NA	Nuclear meets 14 percent of demand in 2016. No large hydro specifically identified.	3,450	existing
6. Transmission/ Distribution	a. 4 kV & 12 kV distribution system – modernize. b. 69 kV – reconductor as needed with high capacity lines if renewable energy park growth warrants. c. 230 kV/500 kV – add 550 MW total, 350 MW upgrade to existing 230 kV (north/south), 200 MW upgrade to existing 500 kV (east/west).	NA NA NA	unknown optional $740 million (lifecycle cost, 2007 dollars)	a. 4 kV & 12 kV distribution system – modernize. b. 69 kV – no action. c. 230 kV/500 kV – add new 1,000 MW capacity Sunrise Powerlink.	NA NA NA	unknown no action $7 billion (lifecycle cost, 2010 dollars)
7. Residential and commercial new growth	Use green building EE design principles to minimize energy demand, incorporate sufficient PV to meet projected annual energy demand.	No net change	Neutral	Growth in annual energy demand and peak demand is quantified in EE/DR line item.	see above	see above
Total annual energy requirement (GWh):		**16,000**			**24,679**	
Peak demand (MW):		**3,500**			**5,060**	
Percentage renewable energy:		**50**			**18**	
New post-2007 local power generation available at peak (MW):		**3,030**			**360**	
GHG emissions assuming domestic natural gas (in tons CO_2):		**2,600,000**			**7,100,000**	
GHG emissions assuming switch to LNG in 2009 (in tons CO_2):		**3,300,000**			**8,800,000**	

Table 1-2. Comparison of Limited San Diego Smart Energy 2020 ($700 million incentives budget) and SDG&E Strategic Plan

	San Diego Smart Energy 2020 – $700 Million Solar Incentive Expenditure			SDG&E Strategic Plan – 2016 $700 Million of Sunrise Powerlink Cost Allocated to SDG&E Customers		
Element	Action	Demand/ supply (GWh-yr)	Electricity cost impact	Action	Demand/ supply (GWh-yr)	Electricity cost impact
2003 baseline annual energy demand:		20,000			20,000	
1. Energy Efficiency (EE) /Demand Reduction (DR)	Reduce energy demand 20%, 4,000 GWh, compared to 2003 baseline of ~20,000 GWh thru EE. Maximize DR thru cooling system EE upgrades and "smart" meters to reduce peak 25% from 2007 peak of 4,636 MW to 3,500 MW.	(4,000)	neutral	Energy demand increases 4,679 GWh relative to 20,000 GWh baseline. Peak demand increases 560 MW to 5,060 MW from 4,500 MW baseline.	4,679	neutral
2020 annual energy demand:		16,000		2016 SDG&E:	24,679	
2020 sources of energy supply – San Diego Smart Energy 2020:				2016 SDG&E sources of energy supply:		
2.Renewable Energy	a. SB 107 - 20% renewable energy by 2010. b. Million solar roofs – 300 MW by 2017. c. San Diego Solar Initiative – 920 MW w/ battery storage for peaking duty at rated capacity, 3-6 pm (1,030 MW w/o storage).	3,500 600 1,700	existing existing $700 million (lifecycle cost, 2007 dollars)	a. SB 107 - adjusted to 2016. b. 300 MW by 2017. c. None.	3,800 600 0	existing existing none
3. Combined heat and power	a. Existing – 350 MW b. New – 700 MW	2,500 5,000	existing neutral	a. Existing – 350 MW b. New – 40 MW	1,800 300	existing neutral
4. Conventional gas-fired power plants	a. Two existing local 550 MW combined-cycles (CC): nighttime and continuous load following. b. Existing local simple cycle peakers, 500 to 700 MW capacity: as needed to meet peak.	2,700 [net]	existing/ neutral existing/ neutral	a. Local and imported CC power, assume 40/60 split. b. Simple cycle peakers: as needed to meet peak.	14,729	power from existing generation
5. Nuclear and large hydro-electric imports	Not necessary to implement strategy.	0	NA	Nuclear meets 14 percent of demand in 2016. No large hydro specifically identified.	3,450	existing
6. Transmission/ Distribution	a. 4 kV & 12 kV distribution system – modernize. b. 69 kV – reconductor as needed with high capacity lines if renewable energy park growth warrants. c. 230 kV/500 kV – add 550 MW total, 350 MW upgrade to existing 230 kV (north/south), 200 MW upgrade to existing 500 kV (east/west).	NA NA NA	unknown optional $740 million (lifecycle cost, 2007 dollars)	a. 4 kV & 12 kV distribution system – modernize. b. 69 kV – no action. c. 230 kV/500 kV – add new 1,000 MW capacity Sunrise Powerlink.	NA NA NA	unknown no action $7 billion (lifecycle cost, 2010 dollars)
7. Residential and commercial new growth	Use green building EE design principles to minimize energy demand, incorporate sufficient PV to meet projected annual energy demand.	No net change	neutral	Growth in annual energy demand and peak demand is quantified in EE/DR line item.	see above	see above
Total annual energy requirement (GWh):		**16,000**			**24,679**	
Peak demand (MW):		**3,500**			**5,060**	
Percentage renewable energy:		**36**			**18**	
New post-2007 local power generation available at peak (MW):		**1,910**			**360**	
GHG emissions assuming domestic natural gas (in tons CO_2):		**3,500,000**			**7,100,000**	
GHG emissions assuming switch to LNG in 2009 (in tons CO_2):		**4,400,000**			**8,800,000**	

Supporting information for Tables 1-1 and 1-2:

a) Definitions: Neutral cost impact – net effect of action will result in no expected increase to customer electricity rates relative to the utility rate basecase; Existing – operational source.
b) All photovoltaic MW capacities are in alternating current - AC.
c) Energy Action Plan uses 2003 as baseline to measure the 20% absolute reduction by 2015 in energy usage at state government and commercial buildings.
d) California's three utilities, PG&E, SCE, and SDG&E, achieved a combined total of 6,200 GWh of energy efficiency savings through 2006. A May 2006 energy efficiency potential study prepared by Itron for California's three regulated utilities estimates that as much as 48,000 GWh of reduction is attainable in existing buildings statewide with cost-effective technologies. SDG&E represents about 10 percent of the California regulated utility load, or nearly 5,000 GWh of additional economic energy efficiency savings.
e) SDG&E assumes smart meters will reduce peak demand by 5 percent. Industry analysts (Brattle Group) estimate smart meters could reduce peak demand by more than 20 percent. Five (5) percent is used as the default assumption to establish a peak demand reduction target of 25 percent (20 percent through energy efficiency - EE, 5 percent through smart meter efficiencies).
f) SDG&E estimates energy demand in 2016 after employing EE measures at 24,679 GWh, and peak power demand in 2016 after employing EE measures at 5,060 MW.
g) All power generation used to meet the SDG&E projected demand increase of 4,679 GWh in 2016 relative to the 2003 baseline is assumed to be met with combined-cycle generation.
h) In order to achieve a 20% renewable generation mix by 2010 based on a 2009 forecast bundled customer retail sales benchmark of 17,418 GWh, SDG&E must obtain a total of approximately 3,484 GWh of renewable energy (8/4/06 application, p. III-9). SDG&E estimates 2015 bundled customer retail sales of 19,076 GWh. 20% of 19,076 GWh is 3,815 GWh.
i) Assume SB1 "million solar roof" PV systems are not equipped with battery storage to operate as afternoon peaking units.
j) *San Diego Solar Initiative* PV systems will be equipped with energy management/battery storage to operate as afternoon peaking units. The cost of energy management/battery storage is assumed to be 10 percent of the overall system cost.
k) Estimate of growth of CHP under SDG&E 2016 case is from SANDAG Energy Working Group Policy Subcommittee recommendations on CHP dated Nov. 16, 2006.
l) SDG&E estimates approximately 1,800 GWh generated from QF (large CHP) and CHP in 2016 (2007-2016 LTPP presented by SDG&E to SANDAG EWG, Jan. 25, 2007, p. 11 bar chart). SDG&E estimates installed QF + CHP capacity in 2015 of 390 MW. The production of 1,800 GWh-yr from 390 MW of capacity equals a capacity factor of 52 percent. CHP will have a primary baseload role in *San Diego Smart Energy 2020*. Average CHP capacity factor under *San Diego Smart Energy 2020* is assumed to be 80 to 85 percent.
m) Explanation of "net" 500 GWh of power from combined-cycle and conventional gas-fired generation: The output of 1 or 2 combined-cycle plants will be needed routinely under the *San Diego Smart Energy 2020* plan at night and during cloudy days, when there is little solar power generation. CHP alone will not be able to meet the nighttime or cloudy day demand. However, on clear days there will be net outflow of power from the San Diego region to neighboring utility areas as the combined solar and CHP output will often exceed local demand in the middle of the day. There will be power flowing in and out of the San Diego area on a continuous basis. The overall effect of this flow from a greenhouse gas calculation standpoint will be 500 GWh of net greenhouse gas emissions from combined-cycle power generation.
n) Nuclear power estimate in SDG&E 2016 case from SDG&E 2007-2016 Long-Term Procurement Plan, Vol. I, as shown in SDG&E presentation to SANDAG EWG, January 25, 2007, p. 11.
o) Estimate of cost to upgrade north/south 230 kV transmission line and 500 kV east/west transmission line to add 550 MW of additional capacity from D. Marcus, June 1, 2007 testimony, in CPUC proceeding A.05-12-014, SDG&E Sunrise Powerlink 8/4/06 application.
p) Estimate of cost of Sunrise Powerlink, $1.265 billion capital cost and $174 million per year for 40 years in 2010 levelized dollars, a total of $6.96 billion, from SDG&E 8/4/06 application.
q) Central heat & power CO_2 emission factor per SDG&E: 639 lb CO_2 per MWh.
r) Combined-cycle CO_2 emission factor: 819 lb CO_2 per MWh (117 lb CO_2 per million Btu, 7 million Btu per MWh).
s) All gas-fired power generation other than CHP is assumed to be combined-cycle generation for greenhouse gas emissions calculation purposes.
t) A total of 14,729 GWh of combined cycle production is assumed for the SDG&E 2016 case (4,679 GWh of demand increase after EE + 10,050 GWh of conventional gas turbine CC power generation). The current combined-cycle capacity factor used by the CEC is 60%. A total of 1,100 MW of local combined-cycle capacity (542 MW Palomar and 561 MW Otay Mesa) will be online in 2016. The expected GWh of electricity production from these two plants in 2016 is projected to be 5,782 GWh at 60% capacity factor. Local generation represents approximately 40 percent of the 14,729 MW of combined-cycle production in 2016. The remaining combined-cycle power production in the SDG&E 2016 case, 8,947 GWh, is assumed to be imported.
u) The CEC assigns a 7.5 percent greenhouse gas penalty to power imported over transmission lines from out-of-state. A factor of 1.075 is applied to the CO_2 emission calculation for the estimated 8,947 GWh of imported combined-cycle power in the SDG&E 2016 case to account for the greenhouse gas penalty assigned to transmission of energy supplies from out-of-state.
v) New post-2007 generation available for peak demand periods: 1) *San Diego Smart Energy 2020* – 2,040 MW PV, 700 MW CHP, 150 MW CSI PV, 40 MW pumped hydroelectric, 133 MW gas-fired peaking turbines. SDG&E 2016 – 40 MW CHP, 150 MW CSI PV, 40 MW pumped hydro, 133 MW gas-fired peaking turbines (J-Power 86.5 MW and Wellhead Power 46.5 MW).
w) The capital cost estimate for the 230 kV and 500 kV transmission upgrades included in *San Diego Smart Energy 2020* is $135 million. The capital cost estimate for the Sunrise Powerlink is $1.265 billion. The lifecycle cost (in 2010 dollars) of Sunrise is estimates at $6.96 billion per SDG&E. The ratio of lifecycle cost to capital cost in the Sunrise case has been applied to the $135 million capital cost estimate for the 230 kV and 500 kV transmission upgrades to calculate an estimated lifecycle cost of $740 million.
x) All GWh annual totals and estimated CO_2 annual emissions are based on the entire electrical demand in SDG&E service territory, including "direct access" customers. *San Diego Smart Energy 2020* assumes all customers in SDG&E service territory participate, including current direct access customers. SDG&E forecasts that direct access customers will represent 23 percent, 5,603 GWh of 24,679 GWh, of the total demand in SDG&E service territory in 2016.
y) The natural gas used in the region that would be displaced by liquefied natural gas (LNG) is from Southwestern raw gas sources with very low (< 1%) CO_2 content in most cases. A few West Texas raw gas sources have significant levels of CO_2. However, this CO_2 is captured at the natural gas processing plant(s) and used in CO_2 enhanced oil recovery projects.
z) SDG&E parent company Sempra Energy will begin operation of its LNG import terminal in Baja California in 2009. At that time Sempra will reverse flow on the SDG&E pipeline network to move natural gas from the LNG terminal north into SDG&E and SoCalGas pipeline systems. 100% of the natural gas in the SDG&E pipeline system will be from the LNG terminal from 2009 forward. Sempra intends to import the LNG from the BP liquefaction plant in Tangguh, Indonesia. The lifecycle CO_2 burden of LNG from Tangguh, including raw gas CO_2 content, liquefaction, shipping, and regasification, is approximately 25 percent greater than that of domestic natural gas from the Southwest. The CO_2 emissions generated under the "domestic natural gas" scenario are multiplied by 1.25 to determine the additional lifecycle CO_2 burden associated with the regional switch to natural gas derived from imported LNG.

2. Understanding the Policy Context for our Region's Energy Future

2.1 California Energy Legislation

2.1.1 AB 32 – California Global Warming Solutions Act, 2006

In September 2006, Governor Schwarzenegger signed into law Assembly Bill (AB) 32, which mandates that California reduce greenhouse gas (GHG) emissions to 2000 levels by 2010 (11 percent below business as usual), to 1990 levels by 2020 (25 percent below business as usual), and 80 percent below 1990 levels by 2050. AB 32 also requires the accounting of GHG emissions associated with transmission and distribution line losses from electricity generated within the state or imported from outside the state. The lead agency within state government tasked with developing the regulatory structure for the implementation of AB 32 is the California Air Resources Board.

2.1.2 SB 1078 – California Renewable Portfolio Standard, 2002

Senate Bill (SB) 1078 requires California's investor-owned utilities, SDG&E, Southern California Edison (SCE), and Pacific Gas & Electric (PG&E) to procure 20 percent of their electric retail sales from eligible renewable resources by the year 2017. Eligible renewable resources include solar, wind, geothermal, and biomass. SB 1078 also requires retail sellers of electricity, including SDG&E, to increase their procurement of renewable energy by 1 percent per year.[1]

2.1.3 SB 107 – 20 Percent Renewable Energy by 2010, 2006

SB 107 codifies the acceleration of California's renewable energy portfolio standard to require that 20 percent of electric sales by retail sellers, except for municipal utilities, are procured from eligible renewable energy resources by 2010. In 2003, the CPUC accelerated the 20 percent renewable resource requirement to 2010. SB 107 codified the CPUC's decision to advance the deadline. SB 107 requires municipal utilities to adopt their own renewable procurement programs and does not subject municipal utilities to a specific renewable resource target.

SDG&E estimates that it must purchase approximately 3,500 GWh of renewable energy in 2010 to meet the SB 107 mandate.[2] Neither the CPUC or SDG&E anticipate that new transmission is necessary to meet this renewable energy mandate.[3,4]

2.1.4 SB1 – California Solar Initiative "Million Solar Roofs", 2006

SB1, the Governor's Million Solar Roofs program, established the goal of 3,000 megawatts (MW) of new, solar-produced electricity by 2017. $3.35 billion in PV incentives has been allocated to meet the 3,000 MW goal.[5] The objective is to achieve a self-sustaining solar market by 2016. The program consists of three components:[6]

- The PUC's "California Solar Initiative" (CSI) provides $2.165 billion in incentives over the next decade for existing residential homes and existing and new commercial, industrial, and agricultural properties. The CSI goal is 1,940 MW.[7] The program is funded through revenues and collected from electric utility distribution rates.
- The California Energy Commission manages a 10-year, $400 million program to encourage solar in new home construction through its New Solar Homes Partnership. The New Solar Homes Partnership goal is 360 MW.
- Local publicly-owned electric utilities, such as the Los Angeles Department of Water and Power and the Imperial Irrigation District, will adopt, implement, and finance a solar initiative program by January 2008. The estimated incentive budget is $784 million. The publicly-owned utility goal is 700 MW.

PV system rebates given through CSI changed from capacity-based payments, scaled to the size of the PV system installed, to performance-based incentives that reward properly installed and maintained solar systems on January 1, 2007. The incentives are determined according to the system size, as follows:

- For PV systems greater than or equal to 100 kW in size, incentives will be paid monthly based on the actual energy produced for a period of five years. This incentive path is called Performance Based Incentives (PBI). Systems of any size may elect to opt into the PBI program. In addition, "building integrated" PV systems, regardless of size, are required to participate in the PBI program.
- PV electricity systems up to 5 MW capacity are eligible, although incentives are paid only for the first 1 MW of capacity.
- All systems less than 100 kW are paid a one-time, up-front incentive based on expected system performance. Expected performance is calculated based on equipment ratings and installation factors, such as geographic location, tilt, orientation and shading. This type of incentive is called Expected Performance-Based Buydown. Residential and commercial incentives receive up to $2.50 per watt, depending on their location, tilt, orientation, and other installation factors. Government and non-profit organizations receive a higher incentive (up to $3.25 per watt) to compensate for their lack of access to the federal tax credit.

The incentive payment levels are automatically reduced over the duration of the CSI program in ten steps, based on the volume of MW of confirmed reservations issued within each utility service territory. On average, the CSI incentives are projected to decline at a rate of 7 percent each year following the start of implementation in 2007.

SB1 also raised the "net metering cap" to 2.5 percent of each utility's peak demand.[8] Net metering allows utility customers to self-generate PV electricity up to the amount of electricity the customer uses during the year. The utility does not pay the customer for any electricity produced beyond the customer's own needs under the net metering format.

2.1.5 SB 1037 – California Energy Efficiency Act, 2005

The primacy of energy efficiency in the State's energy strategy was reinforced with the passage of SB 1037 in September 2005. SB 1037 requires that both the state's investor-owned utilities like SDG&E and locally-owned power providers help meet the state's power needs through energy efficiency and demand reduction. These include energy efficient lights and appliances, and programs that emphasize using less energy or doing tasks at off-peak hours when energy is in less demand. SB 1037 also requires natural gas corporations to have similar policies in place. The law requires that investor-owned utilities (IOU), PG&E, SCE, and SDG&E, exhaust all feasible, cost effective energy efficiency potential in their service areas before pursing any other energy resource options.

SB 1037 requires that an electrical corporation "meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible." Additionally, in "considering an application for a certificate for an electric transmission facility, the commission shall consider cost-effective alternatives to transmission facilities that meet the need for efficient, reliable, and affordable supply of electricity, including…energy efficiency."

2.1.6 AB 117 - Community Choice Aggregation, 2002

AB 117 authorizes customers to aggregate their electrical loads as members of their local community with community choice aggregators (CCA). The bill authorizes a CCA to aggregate the electrical load of interested electricity consumers within its boundaries. AB 117 allows individual municipalities and counties to establish a CCA or join together to form a CCA for the purpose of purchasing power independent of the IOU serving the area. A CCA relies on the utility for electric transmission services only.

AB 117 requires a CCA to file an implementation plan with the CPUC in order for the CPUC to determine a cost-recovery mechanism to be imposed on the CCA to prevent a shifting of costs to the utility's remaining customers. AB 117 requires a retail customer electing to purchase power from a CCA to pay specified amounts for Department of Water Resources contracts and utility costs. This component of AB 117 refers to the 10-year power purchase contracts signed in 2001 during the California energy "crisis" that are administered by the Department of Water Resources.

AB 117 also states generally that it is an objective of the legislation to avoid shifting of recoverable costs between customers. This means that a utility like SDG&E can potentially assign an "exit fee" to customers that would like to form a CCA in the San Diego region. The exit fee can be assigned if the utility can demonstrate to the CPUC that those customers were assumed to a be a part of SDG&E's customer base when SDG&E received approval to ratebase a major new infrastructure investment like the 542 MW Palomar Energy Project in Escondido or the proposed SPL.

2.1.7 AB 1X – Large Commercial Electric Customers Protection Act, 2001

AB 1X was one of the responses to the chaos of the 2000-2001 California energy crisis. AB 1X authorized the Department of Water Resources to purchase power to the meet the power needs of the state's IOUs. AB 1X also protects residential and small commercial utility customers from rate changes for typical levels of electricity consumption. AB 1X provides long-term protection, possibly through the year 2021, from rate increases for these customers.

2.1.8 AB 29X – Large Commercial Customers Must Use Time-Of-Use Meters, 2001

Many of the large commercial customers have been on time-of-use (TOU) meters for years. Over 23,000 advanced interval meters were installed for customers with greater than 200 kW of demand as a result of AB 29X. The legislation required that all meter recipients shift to TOU rates. As a result, much of the potential for peak load reduction from these large commercial customers has already been realized as they have adapted their operations to higher peak prices.

2.1.9 AB 1576 – Modernization of Coastal Boiler Plants, 2005

This legislation authorizes IOUs to enter into long-term power purchase agreements with owners of aging coastal boiler plants to provide the financial mechanism necessary to replace these plants with state-of-the-art, high efficiency combined-cycle plants. San Diego County has two aging coastal boiler plants, 946 MW Encina Power Plant in Carlsbad and 689 MW South Bay Power Plant in Chula Vista. NRG Energy owns the Encina plant. LS Power owns the South Bay plant. NRG Energy filed application with CEC on September 14, 2007 to build a 558 MW dry-cooled combined-cycle replacement plant at the Carlsbad plant site. LS Power filed application with the CEC on June 30, 2006 to build a dry-cooled 620 MW combined-cycle replacement plant at the Chula Vista Plant site.

2.1.10 SB 2431 - Garamendi Principle: Transmission Loading Order, 1988

The Garamendi Principle describes the siting of new transmission lines as inherently controversial and establishes priorities in an effort to guide the development of transmission projects. The Garamendi Principle defines the first priority as upgrading existing transmission lines to avoid the need for new construction. The second priority is defined as constructing new transmission lines in existing transmission corridors to avoid creating new transmission corridors. The last option is the construction of new transmission lines in new corridors if 1) upgrades to existing transmission lines can not provide the needed capacity, and 2) existing transmission corridors are unavailable.

The Garamendi Principle does not address or assign a priority to the replacement of existing transmission structures in state parks with much larger transmission structures having much greater transmission capacity. A map of the proposed route of the SPL through the Anza Borrego State Park, as well as a graphic comparing the size the existing 69 kV transmission poles in the park with the proposed 500 kV SPL towers, is provided in **Attachment A**.

2.2 CPUC and CEC Energy Policy

2.2.1 California State Energy Action Plan

California, through the CEC and the CPUC, has developed the "*Energy Action Plan*"to guide strategic energy decisionmaking. This plan establishes the energy resource "loading order" that defines how California's energy needs are to be met. *Energy Action Plan I* was published in May 2003. *Energy Action Plan II* was adopted in September 2005.[9] *Energy Action Plan II* describes the loading order as "the priority sequence for actions to address increasing energy needs" and then states (p. 2):

> "*The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation*."

2.2.2 CPUC Policy Decisions

<u>Cap on baseload power plant greenhouse gas (GHG) emissions at level of natural gas-fired combined cycle power plant (Decision 06-02-032)</u>: The CPUC adopted a cap on GHG emissions resulting from the generation of electricity used by California consumers on February 16, 2006.[10] The Governor's climate change emission reduction targets are now based in part on all long-term commitments to new electricity generation for use in California coming from sources with GHG emissions equal to or less than those emitted by a new combined cycle natural gas power plant.[11]

<u>Reduce forecasted peak demand by 5 percent from 2007 onward (Decision 03-06-032)</u>: The demand response programs described in this 2006 decision are designed to target the highest 80 to100 hours of demand per year when energy costs are at their highest.

<u>Employ energy efficiency measures to reduce forecasted annual energy consumption by 10 percent by 2013</u> (Decision 04-09-060). The objective of this policy is to reduce electric energy

consumption. SDG&E indicates that it is on a savings goal trajectory that is 118 percent of the cumulative maximum achievable energy efficiency potential.[12] However, in 2006 SDG&E achieved only 41 percent of its CPUC mandated energy savings goal for the year.[13]

Establishment of risk/reward mechanism to financially incentivize utilities to maximize investment in energy efficiency (Decision 07-09-043). The CPUC established a financial incentives framework with this September 20, 2007 decision that rewards utilities with up to 12 percent return on investment for exceeding energy efficiency targets and penalizes the utilities if they achieve less than 65 percent of the target. Utilities generate earnings for shareholders when they invest in “steel-in-the-ground” supply-side resources like power plants and transmission lines, but not when the utilities are successful in procuring cost-effective energy efficiency. This decision addresses this inherent utility bias toward supply-side solutions.[14]

SDG&E advanced metering infrastructure - “smart meters”: On April 12, 2007, the CPUC approved $572 million for SDG&E's Advanced Metering Infrastructure (AMI) project. SDG&E's deployment of AMI is scheduled to begin in mid-2008. From 2008 through 2010, SDG&E will install approximately 1.4 million AMI electric meters and 900,000 AMI gas meters that will measure energy usage on a real-time basis. The intent of these meters is to: 1) improve customer service by assisting in gas leak and electric systems outage detection, 2) transform the meter reading process, and 3) provide real near-term usage information to customers. AMI will be capable of supporting in-house messaging displays and smart thermostat controls, though these innovations are not part of the first phase of SDG&E’s AMI project. The use of AMI meters is expected to reduce the peak demand in SDG&E service territory by approximately 5 percent, in the range of 200 MW, in 2011.

Direct Access: Direct Access was instituted as a part of deregulation of the California energy market. The intent was to allow retail competition. Approximately 20 percent of the power sales in SDG&E service territory are through direct access purchases.[15] Direct access was indefinitely suspended as a result of the volatility in the California energy market in 2000-2001. California entered into long-term contracts to purchase power on behalf of the utilities in response to the energy crisis. At the time direct access was suspended, there was a fear that too many ratepayers would switch to direct access and that these departing customers would strand the costs of energy for the remaining ratepayers. Direct access was suspended to ensure that these long-term power contracts would be paid-off through bundled utility rates.

The long-term contracts are being paid down and the utilities are now authorized to purchase power from other providers. Many businesses, universities, and other commercial-scale entities are supportive of increasing customer choice options and reinstituting direct access. A CPUC proceeding has begun that will consider reinstituting direct access.

3. The Community Choice Aggregation Option

Two entities have formed CCAs since AB 117 was passed into law in 2002, the San Joaquin Valley Power Authority and the City of San Francisco.

The PUC authorized its first CCA application under AB 117 on April 30, 2007. The CCA application was submitted by the Kings River Conservation District (KRCD) on behalf of San Joaquin Valley Power Authority (SJVPA). The SJVPA will serve Clovis, Hanford, Lemoore, Corcoran, Reedley, Sanger, Selma, Parlier, Kingsburg, Dinuba and Kerman, and Kings County.

The introduction to the SJVPA implementation plan provides an excellent summary of the expected benefits of forming a CCA. The following paragraphs are excerpts from the implementation plan:

> "*The Authority's primary objective in implementing this Program is to enable customers within its service area to take advantage of the opportunities granted by Assembly Bill 117 (AB 117), the Community Choice Aggregation Law. The benefits to consumers include the ability to reduce energy costs; stabilize electric rates; increase local electric generation reliability; influence which technologies are utilized to meet their electricity needs (including a potential increased utilization of renewable energy); ensure effective planning of sufficient resources and energy infrastructure to serve the Members' residents and businesses; and improve the local/regional economy.*
>
> *The Authority's rate setting policies establish a goal of providing rates that are lower than the equivalent generation rates offered by the incumbent distribution utility (PG&E or SCE). The target rates are initially at a five percent discount with the discount potentially increasing once additional KRCD-owned resources are brought on-line.*"

The San Francisco City Council voted to form a CCA on June 20, 2007. The mayor of San Francisco approved the city council action on July 2, 2007. A description of the San Francisco CCA implementation plan is provided in the following section.

3.1 Case Study: San Francisco CCA Implementation Plan

San Francisco's renewable energy target is 51 percent renewable energy by 2017. The city will use $1.2 billion in municipal bond financing for construction over the first few years to implement its strategic energy plan.

The CCA will be implemented in two phases. The first phase will cover the first 3 to 4 years where 360 MW of combined resources will be put in place. This includes both energy supply and demand side resources, specifically:

- 107 MW energy efficiency/conservation - goal is to shift more emphasis to peak load reduction compared to current utility energy efficiency programs.
- 150 MW wind power generation.
- 31 MW of onsite PV - this target is embedded in a larger city goal of 50 MW of PV.
- 72 MW of other local distributed energy resources, preferably renewable.

The San Francisco CCA electricity portfolio will be publicly financed using municipal bonds. This significantly reduces the cost of money for building renewable power generation facilities relative to the commercial loans available to private investor-owned utilities or private developers.

An important current element of the economically viability of renewable energy generation is the federal tax credit. The tax credits are intermittent and historically have disappeared from time-to-time. In the case of wind generation, the wind production tax credit is only applicable during the first ten years of operation. After the first ten years the wind farm must be competitive on its own. CCAs are not eligible for these tax credits, as a CCA is a tax-exempt public entity. The CCA, using tax-free bonds, achieves the same or better net cost as the commercial renewable facility with its tax credit. However, CCA avoids the risk of tax credits being unavailable in any given year, and the low-cost financing benefit extends beyond the first ten years through the full financial lifecycle of the asset.

3.2 Comparison of San Francisco CCA and SDG&E Approaches to Renewable Energy

San Francisco will invest $1.2 billion in low cost municipal bonds to achieve 51 percent renewable energy by 2017. By way of comparison, SDG&E estimates a capital budget of $1.265 billion will be needed to construct the proposed SPL to import 1,000 MW of power into the San Diego area. SDG&E is currently subject to a 20 percent renewable energy requirement by 2010.

The California *Energy Action Plan* identifies 33 percent renewable energy by 2020 as a priority goal of Governor Schwarzenegger. The passage of AB 32 in September 2006, which requires a 25 percent reduction in GHG emission levels compared to1990 levels by 2020, has increased pressure to accelerate renewable energy development in the state. In April 2007, SDG&E/Sempra[16] opposed state assembly legislation that would have required California's electric utilities to reach 33 percent renewable energy by 2020.[17] This legislation was defeated in committee.

3.3 CCAs and Public Utilities: Low Cost Project Financing

SDG&E is an IOU. IOU's are for-profit regulated monopolies that are responsible to shareholders. The City of San Diego is served by SDG&E and represents approximately half of SDG&E's customer base. This makes San Diego relatively unique among larger cities in California.

A breakdown of the electricity provider structure in California's seven largest cities is provided in Table 3-1. The City of Los Angeles has its own public utility, the Los Angeles Department of Water and Power (LADWP). Public utilities are non-profit entities responsible to the political leadership of the city or geographic area served by that public utility. For example, the board of directors of the LADWP is appointed by the mayor of Los Angeles. Sacramento has its own public utility, the Sacramento Municipal Utility District (SMUD).

Table 3-1. Electricity Provider Structure in California's Seven Largest Cities

City (ranked by population)	Electricity Provider Type	Name	Access to low-cost municipal bonds to finance energy projects?	Renewable energy target
Los Angeles	public utility	LADWP	yes	35% by 2020
San Diego	IOU	SDG&E	no	20% by 2010
San Jose	IOU	PG&E	no	20% by 2010
San Francisco	CCA	SF CCA	yes	51% by 2017
Long Beach[18]	IOU	SCE	no	20% by 2010
Fresno	IOU	PG&E	no	20% by 2010
Sacramento	public utility	SMUD	yes	23% by 2011

San Francisco is now a CCA. CCA's are in many respects similar to public utilities. However, the CCAs rely on the IOUs serving the area to provide transmission service to customers within the CCA. The IOUs provided both electricity and transmission service to these same CCA customers prior to the formation of the CCA, and continue to provide only transmission service following formation of the CCA.

A private or "merchant" developer would need a 15 percent or more rate of annual profit and would pay 7 percent or more annual interest on any borrowed money. The electric generation plant is primarily built with borrowed money and to a lesser degree with direct investments. A facility built with this financing approach must return at least 10 percent of its value every year in combined interest on loans and investor profits. Over 20 years, a merchant plant would be paid for three times over - once to build it and twice more in the form of interest on loans and profits.[19]

The publicly-owned plants are the least expensive due to low financing costs and freedom from taxes. The IOU power plants are currently less expensive than merchant facilities due to lower financing costs. This is in marked contrast to 2003, when merchant financing costs were at least comparable to those for the IOUs. The change is a reflection of the outcome of the 2000-2001 energy crisis.[20]

One major advantage of public utilities and CCAs is access to low-cost financing. The only cost associated with low-cost municipal bonds available to public utilities and CCAs is the interest on the bond. Municipal bonds have very low interest payments, under 5 percent, as they are issued free of federal tax. Public utility and CCA energy facilities are publicly-owned assets, and for that reason do not need to return a profit. Two costs that private developers must contend with are absent. Over a 20-year period the public energy facility is paid for only twice - once to build it and again to pay the interest on the bond.[21]

The form of financing has a big impact on renewable energy facilities, as most of the cost of these facilities is upfront capital cost. These upfront capital costs carry the burden of having to return interest and profits. This is in contrast to a natural gas-fired plant where 50 percent to 80 percent of the lifecycle cost is fuel, and this fuel is purchased near the time the fuel is needed.[22] Municipal bonds level the playing field for renewable energy facilities, and can make renewable energy facilities competitive in a CCA or public utility structure that would not be competitive for an IOU or private investor.

The CEC recently prepared levelized "cost of power generation" estimates for various central station generation technologies. These levelized costs are useful in evaluating the financial feasibility of a generation technology and for comparing the cost of one technology against another over a 20-year lifecycle. Costs are reported in dollars per megawatt-hour ($/MWh). The $/MWh figure is useful as it allocates costs to the expected hours of operation. Costs vary depending on whether the project is a merchant facility, IOU, or a publicly-owned utility (or a CCA).[23]

Table 3-2 highlights the power project financing advantage of public utilities and CCAs relative to IOUs and merchant (private) developers. For example, the cost of power production from concentrating PV built by a CCA is estimated at $116/MWh. The same project built by a merchant developer has an estimated lifecycle power production cost of $272/MWh.

Table 3-2 also highlights the cost-effectiveness of some renewable energy technologies relative to natural gas-fired combined cycle baseload power plants and simple cycle "peaking" gas turbine power plants. Geothermal and wind power plants are at least as cost-effective as combined cycle power plants on a lifecycle basis. An interesting result of the CEC cost comparison is how cost-effective concentrating PV is relative to simple cycle peaking turbines. Concentrating PV tracks the sun and has an afternoon power production profile that closely follows the late afternoon peak power demand load profile. This makes concentrating PV a direct option to simple cycle peaking turbines. The reason for the superior cost performance of concentrating PV is the fact that in addition to providing peak power during the 100 to 200 hours per year that peaking turbines are typically in operation, concentrating PV provides power at or near its rated capacity whenever the sun is shining.

Large commercial flat plate PV installations are also cost-competitive with simple cycle peaking turbines, assuming current levels of solar incentives and tax credits are available. The addition of sufficient battery storage for flat plate PV to maintain rated capacity through the afternoon peak demand period adds approximately 10 percent to the cost of the PV installation.[24] As shown in Table 3-2, flat plate PV equipped with adequate battery storage to operate effectively as a peaking power plant is cost-competitive with simple cycle peaking turbines even with a 10 percent premium for the battery storage.

Table 3-2. Summary of Levelized Cost of Competing Power Generation Technologies[25]

Year 2007	Size (MW)	Merchant ($/MWh)	IOU ($/MWh)	Public Utility or CCA ($/MWh)
combined-cycle	500	101	94	88
simple cycle	100	586	460	313
small simple cycle	50	633	499	346
geothermal – dual flash	50	89	65	67
concentrating PV	15	272	186	116
parabolic trough	63.5	295	219	155
flat plate PV	1	608	396	256
wind – class 5	50	99	67	61

assumed 2007 natural gas price: $8.34/MMBtu

4. Current State Policies Do Not Incentivize Utilities to Prioritize Investments in Conservation, Renewable Energy, and Distributed Generation

An IOU earns a fixed profit based on the value of the property the IOU owns. Examples of such property are IOU-owned power plants, transmission and distribution lines, and IOU-owned electric and gas meters. In other words, the more an IOU invests in such projects, the more money it earns. When the CPUC, the CEC and the Legislature adopted the *Energy Action Plan* and its associated loading order in 2003, no changes were made to the CPUC's existing ratebasing policies. As a result, the IOUs do not currently have an economic incentive to support the loading order.[26,27]

The CPUC's ratebasing policies have evolved over the last 100 years. The primary type of proceeding where ratebasing policies are addressed is the general rate-setting case. The regulated utility model, used in California up until the 1996 restructuring experiment, called for IOUs to invest shareholder funds in capital projects and to be allowed to recover those costs in rates charged to the ratepayers, along with a rate-of-return (profit) set by the CPUC.

The tendency of the traditional ratemaking formula to encourage over-investment in utility capital projects is well known. Until 1981, California IOUs were focused on building revenues by convincing customers to use more of their product, as these IOUs had more capacity than needed to serve customer load. The IOUs spent money on marketing to get customers to use more gas and electricity. This included promoting all-electric "gold medallion" homes to increase electric demand, and promotions with rebates and discounts to get customers to buy more gas and electric appliances.

The CPUC decoupled IOU energy sales from its revenues for the first time in SDG&E's 1981 rate case decision.[28] The CPUC created a balancing account that allowed SDG&E to increase its authorized rate-of-return even if its overall gas and electric sales dropped due to conservation efforts. In that same decision, the CPUC authorized SDG&E to spend ratepayer money to create a low income weatherization program. This was the first ratepayer-funded conservation program of its kind that paid for the installation of conservation measures in customer’s homes. The 1981 decision ordered SDG&E to initiate the new weatherization program quickly. The decision included an overall corporate rate-of-return penalty for non-compliance.

SDG&E increased its residential conservation programs from1982 onward. The other IOUs in the state also adopted similar programs, starting with their low-income weatherization programs. By 1985 those programs had been expanded to serve commercial and industrial customers as well. The price of oil dropped to approximately $10 to $15 per barrel around 1985, and stayed at that price level for the next several years. Most of the IOU’s conservation programs were dropped or severely cut back during this time period.

A state senate bill mandating that all IOUs provide ratepayer-funded energy conservation was passed in 1989. In response the CPUC convened a proceeding in which it adopted IOU shareholder penalties and rewards based on each IOUs energy conservation program performance. The IOUs set their own goals and the CPUC approved the proposed budget. If the utilities met the goals, they were allowed to recover their program costs in rates. If they failed to meet the goals, they were forced to absorb a portion of those costs. If they significantly exceeded their annual goals, their shareholders were allowed to collect and keep a share of the avoided costs associated with the energy they saved.

California deregulated its energy market with legislation passed in 1996. Prior to deregulation, the IOUs presumed they were going to be forced to divest their power plants and become transmission and pipeline companies only. The CPUC gave indications that ratepayer-funded conservation programs might be dropped and the free market would determine how much, if any, conservation got done by customers. The IOUs began to downsize their conservation departments. In some cases the IOU parent companies started separate unregulated energy service companies. For example, Sempra Energy, parent company of SDG&E, started Sempra Energy Solutions.

In 2002, the CPUC eliminated the IOU conservation penalty/reward mechanism on the basis that the CPUC could simply order the IOUs to pursue conservation. However, the elimination of the penalty/reward mechanism also eliminated penalties for non-compliance. The CPUC reinstated the penalty/reward mechanism for energy efficiency programs in a September 20, 2007 decision.[29]

The CPUC returned ratepayer-funded energy conservation program management responsibilities to the IOUs in 2003. Soon after that, the CPUC also returned long-term resource planning to the IOUs. That put the IOUs back in charge of regional energy resource planning. Today, the IOUs are focused primarily on expanding their CPUC-approved projects that allow full cost recovery through rates charged to customers. An example is Sempra's recent announcement that it plans to invest $8 billion in its subsidiaries, primarily in SDG&E and Southern California Gas Company, for ratebased projects.[30] One of the projects identified in the Sempra announcement is the proposed SPL transmission project.

4.1 SDG&E and Sempra Energy

4.1.1 Sempra Energy – Regional Energy Infrastructure Assets

SDG&E parent company Sempra Energy is an active developer and operator of energy infrastructure projects in and around SDG&E service territory. Sempra owns natural gas-fired power plants in Mexicali, Mexico (600 MW), western Arizona (1,250 MW), Boulder City, Nevada (480 MW), and Kern County, California (550 MW). Sempra built the 542 MW Palomar Energy Project in Escondido and later sold the project to SDG&E in 2005. Sempra is also constructing a liquefied natural gas (LNG) receiving terminal in Baja California approximately 50 miles south of the U.S. border. The company has indicated to the CPUC and the CEC that it is its intends to reverse flow on the SDG&E natural gas pipeline system when the LNG terminal is operational so that natural gas from this facility can be delivered to customers in SDG&E and Southern California Gas Company service territories. As noted, Sempra also owns the Southern California Gas Company.

Sempra owns the entire natural gas pipeline network in Baja California and one 600 MW export power plant in Mexicali. The Sempra plant in Mexicali is connected by two 230 kV transmission lines with a capacity of up to 1,400 MW to the Imperial Valley substation in California.[31] This plant is not physically connected to the Mexican power grid. The Imperial Valley substation is the starting point of SDG&E's proposed SPL.

The Mexican electricity monopoly, Comisión Federal de Electricidad, indicated the addition of a second Sempra plant in Mexicali in its description of its 2003-2007 transmission expansion plan for Baja California.[32] While the second Sempra plant has not yet been permitted or constructed, it is foreseeable that with the existence of the proposed SPL transmission project, Sempra will have a compelling economic incentive to build the second export plant.[33]

The SPL is potentially important to the future energy infrastructure development strategy of Sempra Energy in Baja California, especially if the transmission line ultimately interconnects with the Southern California Edison grid in the Los Angeles area. The Los Angeles area is by far the largest power market in the western U.S. SDG&E has made clear it intends to interconnect the SPL with the Los Angeles area.[34] Maps showing Sempra's pipeline infrastructure in Baja California, existing and proposed export power plants in Mexicali, and the projected pathway of the SPL to the Los Angeles area are provided in **Attachment B**.

4.1.2 Impact of Liquefied Natural Gas Imports on Regional Greenhouse Gas Reduction Efforts

SDG&E is currently projecting a 20 percent reduction in greenhouse gas emissions over the next decade, principally as a result of meeting the state mandate of 20 percent renewable energy generation by 2010.[35] However, this projection does not account for the greenhouse gas burden of converting from domestic natural gas to imported liquefied natural gas.

Parent company Sempra Energy will being shipping liquefied natural gas north through SDG&E's pipeline system from its Baja California liquefied natural gas terminal in 2009.[36, 37] The greenhouse gas burden of liquefied natural gas is approximately 25 percent greater than that of the domestic natural gas SDG&E is currently using.[38] This extra burden is the result of the high levels of CO_2 in the raw gas that will be vented to atmosphere at the gas processing plant,[39] additional energy necessary to liquefy the natural gas, tanker transport across the Pacific, and regasification in Baja California. The net effect of the switch to imported liquefied natural gas in 2009 will be to nullify the 20 percent greenhouse gas reduction by 2016 projected by SDG&E in its current long-term plan. The significance of the switch to liquefied natural gas is explained in more detail in **Attachment C**.

4.2 Reality of Deregulated Energy Market Model

A driving force behind the vision of deregulated energy markets has been the presumption of the need to build transmission "superhighways" across the country to allow consumers to enjoy the benefits of the lowest cost energy available regardless of the physical point of generation. The

California Independent System Operator (CAISO) was created in 1996 to assure the proper functioning of this deregulated market system in California. CAISO is also the representative of the Federal Energy Regulatory Commission in the state. A central role of CAISO is to ensure adequate transmission capacity to allow a deregulated power market to function with minimum physical transmission constraints. However, recent Department of Energy data indicates the cost of power in states that embraced deregulation has risen faster than in states that retained traditional rate regulation.[40]

The concept of eliminating transmission barriers to seeking out the lowest price electricity provider anywhere in the region or country may be obsolete in an environment that now puts a high value on energy security and greenhouse gas reduction. A power plant located in San Diego is inherently more physically reliable than the same plant located hundreds of miles away in Baja California or Arizona or New Mexico. The current high cost of natural gas results in aging and high polluting coal-fired power plants being the lowest-cost electricity providers in the U.S. Yet California's utilities are now prohibited from entering into long-term baseload contracts with power plants that have a greenhouse gas emissions footprint greater than that of a natural gas-fired combined cycle power plant. Coal-fired power plants have a significantly higher greenhouse gas emissions footprint than natural gas-fired combined cycle power plants.

AB 32 also specifically required accounting for the greenhouse gas emissions associated with transmission losses. The transmission loss assumption for the importation of out-of-state power to California is 7.5 percent.[41] The justification for building transmission superhighways under deregulation, obtaining the cheapest electricity wherever it can be found, has been tempered legislatively by the twin objectives of greenhouse gas reduction and energy security.

5. Decoupling Utility Profits from Energy Sales in California[42]

The CPUC adopted an "electric rate adjustment mechanism" for the state's three utilities in the early 1980s. The mechanism sought to ensure that a utility could collect the amount of money needed to recover its fixed costs to counter the effect of conservation programs reducing revenues.

In 1990, the CPUC supplemented this mechanism with a system of performance-based financial incentives for utilities to promote additional cost-effective energy savings. In 1996, as part of its legislation restructuring the electric industry, the state required all customers to pay a charge to fund conservation and renewable energy programs.

The CPUC suspended the "electric rate adjustment mechanism" and the financial incentives following adoption of the restructuring legislation. However, the CPUC adopted a decoupling mechanism for a natural gas utility, Southern California Gas Company, in 1998. The mechanism compensates the company for its costs on a per-customer basis with a set margin per customer, regardless of change in the total amount of natural gas that the company sells. This mechanism provides an incentive for the utility to increase the efficiency of its service delivery per customer.

The California *Energy Action Plan* requires the utilities to first use conservation and demand response measures to minimize increases in electricity and natural gas demand. Next, they must invest in renewable resources and distributed generation. Finally, they can use conventional resources to meet remaining needs. However, the current revenue system does not provide California utilities with a financial incentive to invest in conservation or renewable resources.

The CPUC issued a final decision on September 20, 2007 that rewards the utilities for meeting energy efficiency goals and penalizes the utilities for failure to do so.[43] This decision represents an important step in aligning electric utility financial incentives with the *Energy Action Plan* loading order.

6. San Diego County Energy Profile

6.1 Current Power Generation Sources

The San Diego area currently has approximately 2,200 MW of baseload natural gas-fired power generation capacity. This capacity includes the 542 MW Palomar Energy Project in Escondido, 946 MW Encina Power Plant in Carlsbad, and 689 MW South Bay Power Plant in Chula Vista. Additional baseload capacity includes approximately 200 MW of large cogeneration plants and 150 MW smaller combined heat and power plants. There are approximately 550 MW of peaking gas turbines in the region. SDG&E also receives 450 MW from the San Onofre Nuclear Power Plant located at the northern edge of Marine Corps Base Camp Pendleton. The 560 MW Otay Mesa combined-cycle plant is expected to be in operation by 2009.[44,45] San Diego County power generation sources are listed in Table 6-1.

Not all power sold by SDG&E is generated in San Diego County. The percentage of energy imported by SDG&E is also provided in Table 6-1. In 2007 approximately two-thirds of the energy used by SDG&E customers is classified as imported energy by SDG&E.[46] SDG&E imports power under long-term power contracts signed in the wake of the 2000-2001 energy crisis and administered by the Department of Water Resources. Most of the contract expiration dates are in the 2010 to 2012 timeframe.[47] The company also imports power from sources outside the region, including coal power from neighboring western states.

In 2007 approximately 6 percent of the electric energy by SDG&E, around 1,000 GWh, will be from renewable energy sources.[48] Most of this renewable energy is generated outside of San Diego County. SDG&E is required by SB 107 to generate 20 percent of its retail sales from renewable energy sources by 2010. The major new renewable energy projects that SDG&E is currently proposing are outside of San Diego County. These projects include the 205 MW Pacific Wind project in the Tehacaphi area and the 300 MW Stirling solar dish project in Imperial County.[49] The Pacific Wind project will account for 3.4 percent of the 20 percent target. The Stirling project will account for 2.5 percent of the target.

The reason the solar project produces less energy on an annual basis than the wind project, while having a higher MW design capacity, is because the solar project will not produce energy at the same rate as the wind project. The capacity factor of the solar project, at approximately 0.2, will be lower than that of the wind project at approximately 0.3.[50]

Table 6-1. San Diego County Power Generation Sources and Power Imported by SDG&E

Source	Capacity (MW)	Status	Fuel	Operating Pattern
A. San Diego County generation resources:[a]				
Palomar Energy gas turbine combined cycle[b]	542	operational	NG	baseload
Otay Mesa gas turbine combined cycle	561	2009	NG	baseload
San Onofre nuclear plant[c]	449	operational	nuclear	baseload
Large cogeneration – QF[d]	233	operational	NG	baseload
Small combined heat and power (CHP)	120	operational	NG	baseload
Encina Power Plant – five boilers[e]	946	operational	NG	load following and peaking power
South Bay Power Plant – four boilers[f]	689	operational	NG	load following and peaking power
Simple-cycle gas turbines, pre-2000 [14 total, 1970s vintage]	200	operational	NG	peaking power
Simple-cycle gas turbines, post-2000 [8 total - Calpeak units (3) on DWR contract]	342	operational	NG	peaking power
Simple-cycle gas turbines, proposed [J-Power 86.5 MW, Wellhead Power 46.5 MW]	133	2008	NG	peaking power
Wind – Crestwood/Kumeyaay project	50	operational	none	intermittent
Solar – rooftop photovoltaic (PV)	38	operational	none	sunny days
Landfill gas + WWT digester gas	19	operational	methane	baseload
Bullmoose biomass project	20	2009	biomass	baseload
Hydroelectric – pumped storage [Lake Olivenhain – Lake Hodges]	40	2008	none	peaking power
Small hydroelectric	2	operational	none	baseload
B. SDG&E projected power imports as percent of forecast 2007 retail power sales:[g]				
Natural gas – DWR long-term contracts[h]	22 percent			
Coal	12 percent			
Nuclear[i]	20 percent			
Large hydroelectric	9 percent			
Renewable energy[j]	4 percent			
Import percentage, 2007 SDG&E sales:	67 percent			

Notes:

a) Sources of in-county data are: SDG&E 2007-2016 Long-Term Procurement Plan (LTPP), Exhibits, Exhibits IV-6 (2007 year) and IV-10; Aug. 4, 2006 SPL CPCN application, p. III-17, Table III-1 (list of renewable resources); proposed peaker gas turbine estimate from SDG&E May 14, 2007 press release – "*SDG&E selects projects to meet peak-power demand in 2008*"; PV estimate from 2nd quarter 2007 SDG&E quarterly compliance filing with CEC on PV interconnection; CHP estimate from SANDAG EWG, *Policy Subcommittee Recommendations for Energy Working Group (EWG) Legislative Efforts*, November 16, 2006.

b) SDG&E filed a petition with the CEC on July 27, 2007 to add a centralized chiller to cool the inlet air to the two combustion turbines at Palomar Energy. The modification will provide up to 40 MW of additional capacity to meet summer peak loads.

c) SDG&E has 20 percent ownership of the 2,254 MW San Onofre nuclear plant. SCE has 75% ownership of the plant.

d) The 55 MW cogeneration plant in Yuma, Arizona under QF contract with SDG&E is included in the 233 MW total.

e) Owner NRG Energy filed application with CEC on September 14, 2007 to build 558 MW combined-cycle replacement plant.

f) Owner LS Power filed application with CEC on June 30, 2006 to build 620 MW combined-cycle replacement plant. SDG&E assumes that South Bay will be permanently shut down in 2009 its Aug. 4, 2006 application to the CPUC for Sunrise Powerlink.

g) Sources of imported power data are: August 2007 SDG&E "*power content label*" utility bill insert; SDG&E Jan. 25, 2007 PowerPoint presentation to SANDAG EWG on 2007-2016 LTPP (p. 11, graphic showing DWR contracts at 22% of sales - 2007).

h) SDG&E was assigned the Williams A, B, and C, Sunrise Power Company (Kern County), and CalPeak long-term power contracts by the Department of Water Resources (DWR) as part of the resolution of the California 2000-2001 power crisis.

i) Although San Onofre nuclear plant is located in San Diego County, SDG&E classifies power supplied by the plant as imports.

j) SDG&E forecasts renewable energy resources will supply 6% of total sales in 2007. In-county renewable energy sources are estimated to provide approximately 2% of total sales. Approximately 2/3 of the renewable energy, 4% of sales, will be imported.

6.2 Electric Energy Consumption and Peak Power Demand Trends

Electric power demand is measured in two ways for resource planning purposes: 1) total electric energy usage over the course of a year, and 2) peak power demand during hot summertime conditions. Annual energy usage is analogous to the total gallons of fuel used by an automobile over the course of a year. Peak power demand is analogous to the maximum horsepower required of the automobile when it is fully loaded and must maintain a high rate of speed while driving up a hill. Electricity planning in California is largely guided by peak power demand.

The residential electricity consumption in SDG&E service territory is approximately 8,000 "gigawatt-hours" (GWh) per year. Commercial and industrial electricity consumption adds another 12,000 GWh per year of demand, for a total annual demand in the range of 20,000 GWh per year.

The use of GWh as the unit of measure of annual energy usage is done for convenience. For example, a typical residence in the San Diego area consumes about 0.8 kilowatt of electricity on average.[51] There are 8,760 hours in a year. SDG&E serves 1.2 million residences. Therefore residences in SDG&E service territory consume about 8,000 million kilowatt-hours (kWh) in a year. This is an unwieldy number. For that reason it is more common to speak in energy units of GWh. One GWh equals one million kWh.

Peak power demand is measured in megawatts (MW). One MW equal one thousand kW.

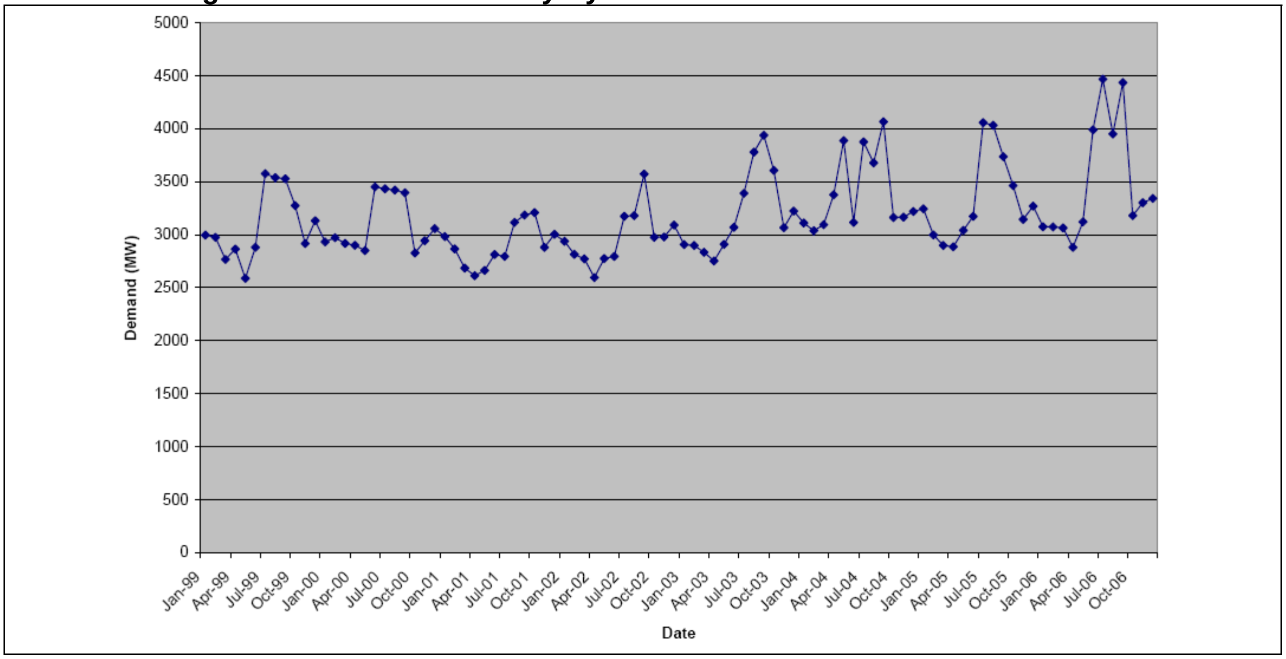
Table 6-2 shows the current trend in annual and hourly energy consumption in SDG&E service territory. The 2004 electricity consumption data is based on reported information. The 2007 and 2016 electricity consumption values are forecasts prepared by SDG&E. The 2016 forecast assumes a demand growth rate of more than 1.5 percent per year in the 2010-2016 timeframe for energy usage and peak power demand.

Table 6-2. Trends in Annual and Hourly Consumption

	2004[52]	2007[53]	2016[54]
Annual energy usage in SDG&E service territory, GWh per year	20,578	21,721	24,679
Average hourly usage in SDG&E service territory, MWh	2,349	2,480	2,817

Peak power demand in SDG&E service territory in 2007 reached 4,636 MW.[55] This is nearly twice the average demand level on an annual basis. Peak demand is primarily associated with heavy usage of air conditioning systems on hot summer afternoons. The peak demand trend over the 1999-2006 period is shown in Figure 6-1. Adequate electric power generation capacity must be maintained to provide power even on the hottest day of the year to avoid power curtailments. For this reason, a large number of gas turbine power generators are located in the region to provide extra power for as little as 100 hours a year to address this peak demand. These units are idle 98 to 99 percent of the time. This is an expensive and inefficient way to address peak power demand.

Figure 6-1. SDG&E Monthly System MW Peak Demand: 1999-2006[56]



6.3 SDG&E Population Growth Forecast and Actual Growth Trend

SDG&E projects a growth in peak electricity demand of just over 60 MW per year in the 2007-2016 timeframe.[57] A major factor contributing to this growth in peak demand forecast by SDG&E by 2016 is the assumption of robust population growth. SDG&E uses a private proprietary population forecast service, Moody's "economy.com," to project load growth.[58] SANDAG relies on U.S. Census Bureau statistics for its regional population forecasts. Powers Engineering purchased the San Diego County population growth forecast from economy.com to cross-check the data used by SDG&E with U.S. Census Bureau data. The economy.com population data is provided in **Attachment D**.

The population growth assumed by SDG&E in calculating electricity demand increases over the 2007-2016 time period is much higher than the actual 2000-2006 population growth trend for San Diego. SDG&E assumes a steady population increase of 1.1 percent per year over the coming decade.[59] U.S. Census statistics for San Diego County show an average population growth rate from 2000 to 2006 of 0.7 percent per year, and a July 1, 2005 to July 1, 2006 growth rate of less than 0.2 percent.[60,61] U.S. Census statistics show San Diego County growing at a much slower rate that California as a whole from April 1, 2000 through July 1, 2006, 4.5 percent growth versus 7.6 percent statewide.[62]

SDG&E derived the energy and peak demand forecasts used in the 2007-2016 Long-Term Procurement Plan from the CEC's June 2006 updated demand forecast. The CEC data is statewide. As noted, the San Diego County growth rate is much lower than the statewide growth rate. Use of CEC statewide data will result in a significant overestimate of the energy and peak demand for San Diego County.

U.S. Census forecasts California increasing its population by 12.4 percent in the 2000 – 2009 period.[63] At its current rate of growth, San Diego County will not achieve a growth rate even one-half the rate that the U.S. Census projects for California for the period 2000 through 2009. Census projects a slower population growth rate for California in the 2010-2019 period, averaging 1.0 percent per year during the period. Yet the economy.com data used by SDG&E forecasts an average San Diego County population growth rate of 1.55 percent per year for the 2010-2019 period, 50 percent higher than the U.S. Census forecast for California as a whole and more than double the San Diego County growth for the 2000-2009 period of 0.7 percent per year provided in the same economy.com forecast database.[64]

One historically unique factor that makes it unlikely that San Diego County will approach the high population growth rates assumed by SDG&E in projecting electric power demand over the next decade is the extraordinarily high cost of housing. It is highly unlikely that this unprecedented disparity between the average price of a home, approximately $550,000,[65] and the typical income level of San Diego County residents will rectify itself over the next ten years. In San Diego County, only 9 percent of the workers earn more than $75,000 per year. Thirty (30) percent earn between $35,000 and $75,000 per year, and 61 percent earn less than $35,000 per year.[66] It is highly speculative to forecast a major new influx of residents to the county unless a major reduction in the cost of housing is also being forecast.

7. Recent Strategic Energy Plans for the San Diego Region

7.1 San Diego Regional Energy Strategy 2030

The *San Diego Regional Energy Strategy 2030* (RES 2030) was prepared for SANDAG in the spring of 2003.[67] Many of the principal San Diego area government, industry, and public interest stakeholders were involved in the process of developing the document. SANDAG is the San Diego County regional planning agency. The SANDAG Board of Directors is composed of the mayors of all the incorporated cities in San Diego County, as well as a representative from the San Diego County Board of Supervisors. *RES 2030* was adopted by the SANDAG Board of Directors on July 25, 2003. The goals defined in *RES 2030* are described in Table 7-1.

Table 7-1. Goals of San Diego Renewable Energy Strategy 2030

RES Goal	Goal Description
1	Achieve and represent regional consensus on energy issues at the state and federal levels.
2	Achieve and maintain capacity to generate 65% of summer peak demand with in-county generation by 2010 and 75% by 2020.
3a	Increase the total electricity supply from renewable resources to 15% by 2010 (~740 MW), 25% by 2020 (~1,520 MW) and 40% by 2030 (~2,965 MW).

3b	Of these renewable resources, achieve 50% of total renewable resources from resources located within the County (~370 MW by 2010, ~760 MW by 2020, and ~1,483 MW by 2030).
4	Increase the total contribution of clean distributed generation resources (nonrenewable) to 12% of peak demand by 2010 (~590 MW), 18% by 2020 (~1,100 MW) and 30% (~2,225 MW) by 2030.
5	Increase the transmission system capacity as necessary to maintain required reliability and to promote better access to renewable resources and low-cost supply.
6	Reduce per capita electricity peak demand and per capita electricity consumption back to 1980 levels.
7	Develop policies to insure an adequate, secure and reasonably priced supply of natural gas to the region.
8	Reduce regional natural gas per capita consumption by the following targets: 5% by 2010, 10% by 2020, 15% by 2030.
9	Complete a transportation energy study by June 2004 to evaluate the potential savings through more efficient use of transportation technology and fuels.

The goal of achieving 1980 levels of per capita electricity peak demand and per capita electricity consumption by 2030 represents a 15 percent reduction from the 2002 baseline year. *RES 2030* provides a sketch of how the per capita reduction in electricity usage will be achieved:

> *"The evolution of technology is such that significant savings are possible in appliances, new construction and in particular, existing construction. For example, the emergence of light emitting diodes in a broad range of lighting applications could reduce lighting demand by as much as 90 percent. Retrofit of existing buildings with off-the-shelf technology can reduce consumption by as much as 60 percent. Although society is demanding more and more electric appliances, energy efficiency and smart energy devices will reduce their consumption significantly. Strategies to reduce energy used per capita should consider new technologies to the extent that they will be more efficient, environmentally benign and reduce reliance on fossil fuels."*

RES 2030 also established the goal of reducing regional natural gas per capita consumption by 15 percent by 2030 is to be achieved by:

- Re-powering or replacement of the existing power plants with high efficiency combined cycle turbines by 2010 and 2015, respectively.
- Increase use of solar water heating in residential, pool and commercial uses to offset natural gas demand.
- Promote the use of high efficiency distributed generation technologies (such as combined heat and power).
- Promote the insulation of un-insulated homes built before the development of building energy codes.

RES 2030 has served as the reference point used by SANDAG to provide comment on proposed energy infrastructure projects. The biggest energy infrastructure project proposed in decades in the region is the proposed SPL transmission project. The SANDAG Board of Directors voted unanimously to take no position on the proposed transmission project on November 17, 2006. The supporting discussion to the “no position” resolution is instructive in explaining the role of *RES 2030* in guiding SANDAG to adopt a neutral position toward the transmission line:[68]

> *“The Regional Energy Strategy (RES), which was adopted by the SANDAG Board of Directors on July 25, 2003, is being used as a basis for the EWG (Energy Working Group of SANDAG) review of the proposed SPL (Sunrise Powerlink). The RES promotes a mix of power production from centralized and distributed generation resources. Distributed generation is power generated at or near its point of use, typically smaller and more efficient than centralized facilities. The RES recognizes the need for local and imported power but calls for the majority of power used by San Diegans to be produced locally. Several goals in the RES address electricity supply and infrastructure capacity.*
>
> *The RES includes a goal of increasing the total electricity supply from renewable resources to 15 percent by 2010, 25 percent by 2020, and 40 percent by 2030. Subsequent to adoption of the RES, more stringent state law has been adopted requiring 20 percent renewables by 2010. The Governor also has proposed an additional goal of 33 percent renewables by 2020. The use of transmission is needed to meet the renewables goal, but it is unclear whether this need could be met using existing or other new transmission options. Currently, there is no assurance that the SPL will be used to deliver a significant amount of renewable power to the region. It also should be noted that the RES goal calls for an emphasis on in-region renewable installations.*
>
> *The RES includes a goal to increase the transmission system capacity as necessary to maintain required reliability and to promote better access to renewable resources and low-cost supply. This goal could be met through improvements to existing transmission infrastructure, from the SPL, or from other transmission options currently under review at the state and federal levels.”*

SANDAG is also engaged in SDG&E’s long-term planning process. SANDAG described how the substantive aspects of the *RES 2030* should be incorporated into SDG&E’s long-term plan in a September 8, 2006 letter to SDG&E that was included as an attachment to SDG&E’s long-term plan submittal to the CPUC. The September 8, 2006 SANDAG letter is included as **Attachment E**.

7.2 SDG&E 2007-2016 Long-Term Procurement Plan

SDG&E submitted its 2007-2016 Long-Term Procurement Plan (LTPP) to the CPUC on December 11, 2006.[69] The major elements of the LTPP are summarized below.

Energy efficiency and peak demand reduction:

- Energy efficiency should reduce forecast peak demand by 487 MW and 2,561 GWh by 2016 (~40 MW per year peak reduction attributable to energy efficiency).
- Demand response programs expected to produce a 5 percent peak reduction (249 MW).

- Distributed generation (DG) including California Solar Initiative will reduce peak load by 225 MW (at time of peak), with the expectation that CSI will produce 150 MW (out of 300 MW forecast); rate of DG increase is about 1 to 2 MW per year currently.

LTPP includes scenarios with and without SPL:
- Add resources with attention to the *Energy Action Plan* loading order.
- SDG&E ran high, low, base case scenarios for need through 2016.

Renewable energy:
- Sixteen (16) percent of energy need is currently under contract as renewables (including the dish Stirling solar contract), with assumption that SDG&E may contract for more than 20 percent total (to account for shortfalls, cancellations) to meet overall renewable energy goal.
- New transmission is essential for cost-effective procurement to meet 20 percent goal by 2010.

Conventional power generation resources:
- Assume South Bay Power Plant retires in 2009.
- Encina Power Plant stays online.
- AB 1576 does not give repowering and replacement (of aging coastal power plants) any unique status that puts them at the head of the contract "line."
- 250 MW of new peaking gas turbines will be added in 2008-2009.

AB 32 greenhouse gas mitigation and reduction:
- Reduction goal levels not yet known, baseline for reduction has not yet been established (could be 1990, current or other year).
- GHG emissions will only see a substantial reduction if baseload plants become more efficient.

Distributed generation:
- No specific set-asides listed for combined heat and power.

7.3 Additional Strategic Plans Developed for the San Diego Region

Four additional strategic assessments have been developed for the San Diego region or areas within the region. The common thread between these assessments is an examination of the benefits and costs of moving to a renewable energy future. These assessments are summarized in **Attachment F** and include:

7.3.1 Perspectives on Regional Renewable Energy Potential

Energy Parks to Balance Renewable Energy in San Diego Region (July 2007).[70] This assessment evaluates the potential for developing a large number of 5 to 10 MW renewable energy power generation facilities in the more rural areas of San Diego County on commercially-available land. Concentrating solar technologies, such as concentrating PV, are emphasized. Energy parks would be limited to 5 to 10 MW per site, equivalent to approximately 25 to 50 acres, primarily because of the difficult topography. The study includes an initial assessment of the quantity of commercial land potentially available for this purpose. A programmatic environmental siting process for suitable commercial land is recommended to reduce siting uncertainty and facilitate financing of these projects.

Creating a Sustainable Economy – San Diego/Tijuana Case Study (March 2007).[71] The energy portion of this report projects: 1) the amount of land area necessary to meet regional energy needs using rooftop PV, and 2) the economic benefits that would result from converting to PV-based power generation from current fossil fuel-based power generation. The report concludes that all the region's electricity needs could be met by solar energy by fully utilizing the PV potential of existing residential, commercial, and parking areas. The report also projects substantial economic benefits by meeting local power needs with PV in the region instead of sending dollars out of the local economy to purchase fossil fuel-based electric power.

Green Energy Options to Replace the South Bay Power Plant (February 2007).[72] This study analyzes options for replacing the capacity of the South Bay Power Plant in the context of a Chula Vista CCA. Three different levels of renewable energy generation are assessed, 50 percent, 70 percent, and 90 percent. The estimated wholesale price of power generation is estimated between \$0.08/kWh and \$0.11/kWh for these three scenarios. Current SDG&E energy charges average in the range of \$0.13/kWh and \$0.17/kWh depending on level of consumption. The study underscores a key advantage of non-profit, public CCA structure – access to low-cost municipal bond financing. The study also highlights that access to this low-cost financing makes renewable energy projects more cost-competitive under public financing than when financed by IOUs or private developers.

Potential for Renewable Energy in the San Diego Region (August 2005).[73] This analysis looked at the renewable energy potential in the region, including San Diego County, Imperial County, and wind power just over the border in Baja California. The estimated peak output technical potential of residential and commercial PV in 2010 is 4,348 MW, 1,624 MW commercial PV and 2,722 MW residential PV, with an associated annual energy production of approximately 7,000 GWh. This estimate does not include the technical PV potential of parking areas and parking structures. The technical potential of concentrating solar technology in more rural areas of San Diego County is estimated at 2,900 MW and 5,000 GWh.

7.3.2 Photovoltaic Potential of Parking Lots and Parking Structures

As noted, *Potential for Renewable Energy in the San Diego Region* does not include an estimate of the PV potential of open ground-level parking lots or parking structures. It is necessary to have a rudimentary idea of the PV potential of parking areas and parking structures in the San Diego region, since these are often ideal candidates for commercial-scale PV arrays. The 250 kW PV array on the Qualcomm campus parking structure in Sorrento Valley, and the 235 kV Kyocera "solar grove" PV array in Kearny Mesa, are two examples of the potential of parking structures and ground-level parking lots. Descriptions of these two installations are provided in Section 12 of this report.

Envision Solar is a San Diego-based company that evolved out of the development of the 235 kV "solar grove" PV array in the parking lot of the Kyocera facility on Kearny Mesa. Envision Solar specializes in the development of PV arrays for ground-level parking lots. Powers Engineering requested an estimate of the parking lot square footage in San Diego County from Envision Solar. The rough estimate of the actual PV potential of open parking lots and parking structures is 3,000 MW.[74] This estimate assumes that only 25 percent of total estimated parking surface in the county is sufficiently open, meaning not shaded to a significant degree, that its full solar potential can be realized. The assumptions used to develop the 3,000 MW estimate of PV potential for open parking lots and parking structures are provided in Table 7-2.

Table 7-2. Assumptions Used to Estimate PV Potential of Parking Lots - San Diego County

Assumption	Source
771 vehicles per 1,000 citizens	Dr. Donald Shoup, urban planning, UCLA
At least 4 parking spaces per vehicle, one of which is residential space	Dr. Donald Shoup, urban planning, UCLA
3,000,000 people	Approximate San Diego County population, 2006 U.S. Census update
162 square feet	Square footage of typical 9-foot by 18-foot parking space, Envision Solar
6,939,000 non-residential parking spaces in San Diego County	calculated value: 3,000,000 × (771/1,000) × 3 spaces [4 total spaces per car – 1 residential space per car]
11 watts per square foot	PV capacity per square foot of parking area, in alternating current (AC) output, Envision Solar
12,365 MW	parking lot PV technical potential, calculated value: 6,939,000 spaces × 162 square feet per space × 11 watts per square feet × 1 MW per million watts
3,000 MW	Rough estimate of actual PV potential - assumes 25 percent of non-residential parking spaces are unshaded throughout the day and full PV potential can be realized at these sites, Powers Engineering[75]

8. Energy Efficiency - First in the Loading Order

8.1 Forecast Energy Efficiency Reductions vs. Real Reductions

Energy Action Plan II (2005) lists specific steps to be taken to reduce energy demand in California. For example, it specifically calls for the implementation of actions outlined in the governor's 2004 *Green Buildings Action Plan* to improve building performance and reduce grid-based electrical energy purchases in all state and commercial buildings by 20 percent by 2015, per Executive Order S-20-04. Executive Order S-20-04 states that:[76]

> *"Commercial buildings use 36 percent of the state's electricity and account for a large percentage of greenhouse gas emissions, raw materials use and waste.*
>
> *It is ordered that state agencies, departments, and other entities under the direct executive authority of the Governor cooperate in taking measures to reduce grid-based energy purchases for state-owned buildings by 20 percent by 2015, through cost-effective efficiency measures and distributed generation technologies.*
>
> *The California Public Utilities Commission (CPUC) is urged to apply its energy efficiency authority to support a campaign to inform building owners and operators about the compelling economic benefits of energy efficiency measures; improve commercial building efficiency programs to help achieve the 20 percent goal; and submit a biennial report to the Governor commencing in September 2005, on progress toward meeting these goals.*
>
> *The CEC will undertake all actions within its authority to increase efficiency by 20 percent by 2015, compared to Titles 20 and 24 non-residential standards adopted in 2003; collaborate with the building and construction industry state licensing boards to ensure building and contractor compliance; and promptly submit its report as per Assembly Bill 549 (Statutes of 2001) on strategies for greater energy and peak demand savings in existing buildings."*

The objective described in *Energy Action Plan II* is unambiguous for government and commercial buildings – a 20 percent reduction in grid-based energy purchases by 2015 compared to a concrete 2003 baseline. Executive Order S-20-04 states that government and commercial buildings consume 36 percent of the state's energy. It is of value to calculate what the impact of a 20 percent reduction in energy purchases by government and commercial buildings in SDG&E service territory would have on the electricity demand projected by SDG&E for 2015.

Total electric power consumption in SDG&E service territory in 2003 was approximately 20,000 GWh.[77] A 20 percent reduction below the 2003 total is a reduction of 4,000 GWh. The resulting total annual electric power consumption would be 16,000 GWh.

The City of San Diego has been very active in conducting energy efficiency upgrades to city buildings. The city has carried-out approximately 70 energy efficiency upgrade projects to date under a CEC low-interest-rate loan energy efficiency incentive program. The primary requirement of this loan program is that each qualifying project has a simple payback of no more than 10 years. The average energy efficiency improvement for these City of San Diego projects is approximately 20 percent based on the most recent energy consumption measurements.[78]

SDG&E promotes the energy efficiency potential of new and remodeled commercial buildings through its Sustainable Communities Program.[79] A Sorrento Valley business, TKG Consulting Engineers, Inc., was recognized by SDG&E for achieving a 30 percent reduction in energy usage beyond the California new building energy efficiency standard. In regard to this remodeling project, SDG&E notes, "*TKG's new office building is a model for other San Diego County projects. It demonstrates that energy efficiency, occupant comfort, and environmentally friendly design is cost-effective, and be achieved even with a tight construction schedule*."[80]

The energy efficiency of the TKG building was improved by: 1) adding insulation to the interior of the existing concrete walls, 2) adding a film to the existing single glazed windows, 3) use of a variety of high efficiency lighting strategies, 4) occupancy sensors for private offices, 5) and use of a high efficiency air conditioning system. SDG&E also sited a 40 kW PV array on the roof of the TKG building to provide renewable power to the utility's distribution grid. This is a potential model for the local siting of utility-owned PV generation.

Energy Action Plan II also describes ambitious energy efficiency goals for the utilities, stating:

> *"For the past 30 years, while per capita electricity consumption in the US has increased by nearly 50 percent, California electricity use per capita has been approximately flat." and "Most recently, in September 2004, the CPUC adopted the nation's most aggressive energy savings goals for both electricity and natural gas. In achieving these targets, the IOUs (investor-owned utilities) will save an additional 5,000 MW and 23,000 GWh per year of electricity, and 450 million therms per year of natural gas by 2013."*

The goals described by the CPUC represent a 10 percent reduction over business-as-usual. The utilities would be well on the road to achieving an overall absolute 20 percent reduction in electric power consumption by 2015 if the goals described in this excerpt from the *Energy Action Plan* were referenced to a 2003 baseline.

These goals are not referenced to a 2003 baseline. The goals are referenced to utility projections of future demand. The flaw in energy efficiency requirements imposed by the CPUC on utilities is that the energy efficiency and demand response savings are calculated relative to forecast energy usage and peak demand, not a fixed baseline year. As a result, the utility can assume high per capita growth in electricity consumption, combined with robust population growth, to forecast very high energy usage rates prior to the application of energy efficiency measures. The utility then applies energy efficiency measures to this high projected usage to eliminate 10 percent of this consumption by 2013. This is a "paper" reduction in demand. The on-the-ground reality of these high forecasts and paper reductions is an ever-increasing demand for electricity. That is why energy efficiency gains should be measured relative to a baseline year, as in Executive Order S-20-04, to be meaningful.

SDG&E is projecting that both per capita energy consumption and per capita peak electricity demand will increase in SDG&E service territory between 2007 and 2016.[81] This forecast increase runs counter to California's 30-year history of "no change" in per capita energy consumption. It is the reliance on forecast paper reductions instead of absolute reductions relative to a fixed baseline year that allows SDG&E to state in the 2007-2016 Long-Term Procurement Plan that "*SDG&E does not believe that significantly more energy efficiency savings could be realistically achieved from a technical standpoint*."[82]

8.2 Maximizing Energy Efficiency Reductions

SDG&E could save an additional 4,800 GWh through expanded, cost-effective energy efficiency programs. This is nearly 25 percent of the San Diego region's current annual energy consumption of approximately 20,000 GWh. Major efficiency opportunities include greatly expanded upgrades/replacement of cooling systems, lighting, refrigeration, and greatly expanded weatherization programs. A 2020 target date to achieve a 20 percent reduction in energy consumption and peak demand would allow time to re-design the current energy efficiency program so that all economically justifiable energy efficiency retrofits are carried-out. This target date would also allow convenient phase-in of long-life high efficiency devices as the original devices, specifically central air conditioning units and refrigerators, reach the end of their useful lives.

All energy efficiency upgrades with a reasonable energy savings payback period reduce energy costs in SDG&E's service territory. Energy efficiency measures also drop greenhouse gas emissions and air pollution. It is for these reasons that energy efficiency is first in the loading order. However, realizing full energy efficiency benefits will only occur if the utility or a delegated third party funds the efficiency upgrades as a standard, across-the-board practice for all customers. Customers are unlikely to decline an efficiency upgrade if they incur no additional out-of-pocket expenses and the utility or a designated third party manages the transaction to minimize customer inconvenience.

8.2.1 Cost-Effective Energy Efficiency Potential

California's three IOUs achieved a combined total of 6,200 GWh of energy efficiency savings through 2006. However, the CPUC wants utilities to develop far bolder energy-saving strategies to improve grid reliability and cut customer costs. The Utility Ratepayers Network (San Francisco) has indicated that the difference between economically achievable energy efficiency reductions and what has actually occurred to date is so stark that a different utility energy efficiency program design and longer-term market strategies must be considered.[83]

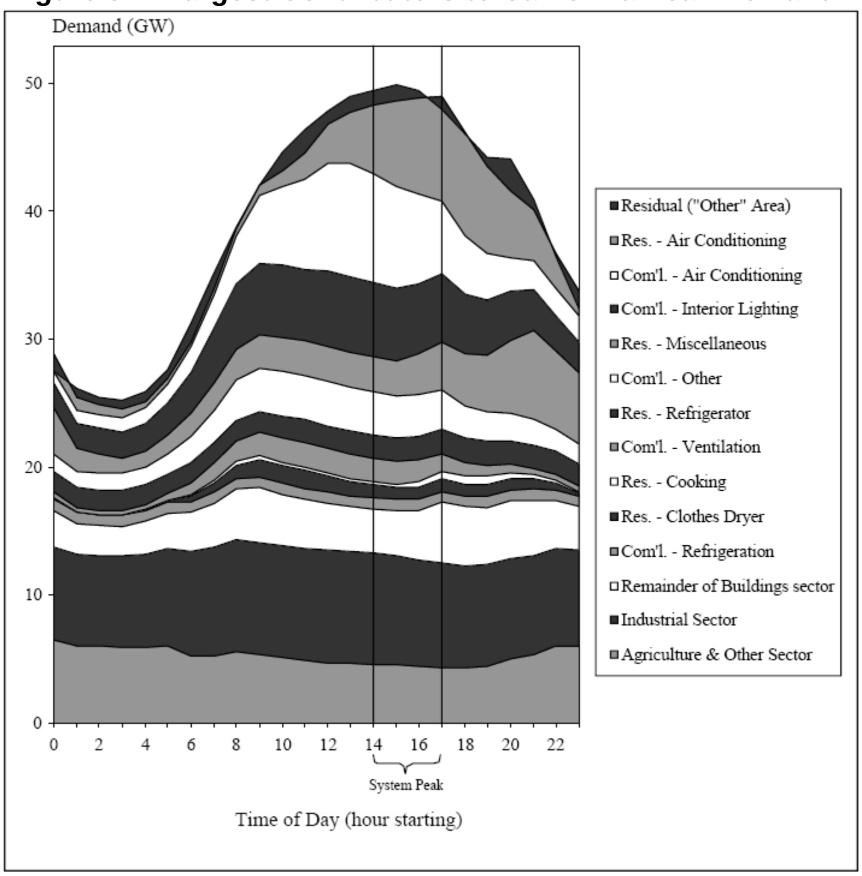
A May 2006 energy efficiency potential study prepared by Itron, Inc. for California's three IOUs estimates that as much as 48,000 GWh of reduction is attainable in existing buildings statewide with economical technologies.[84] The study identifies that 58,000 GWh is technically possible in existing structures, though not all 58,000 GWh would be considered cost-effective using the cost comparison methodology currently applied.

SDG&E represents about 10 percent of the California IOU load. Ten (10) percent of the 48,000 GWh of cost-effective statewide energy efficiency reduction potential is 4,800 GWh, about one-quarter of the estimated 20,000 GWh in total annual power sales in SDG&E service territory.

8.2.2. High Value Energy Efficiency Opportunities in San Diego County

Figure 8-1 provides a breakdown of the demand by device type on hot summer days. Air conditioning load is the dominant contributor to peak power demand on the hottest days of summer, comprising approximately one-third of total demand. In SDG&E service territory, this means a 1,500 MW air conditioning load out of a peak load of up to 4,600 MW. The statewide relationship between air conditioning load and peak load for 2005 is provided in **Attachment G**. Despite the predominance of air conditioning load during peak demand periods, relatively little forward progress has been made in reducing this load.

Figure 8-1. Largest Contributors to California Peak Demand[85]



SDG&E relies on the May 2006 Itron study in measuring its energy efficiency performance.[86] SDG&E uses the Itron study as the yardstick in assessing energy efficiency savings projected by SDG&E compared to the universe of technically achievable energy efficiency savings identified by Itron. Itron is also a contractor to SDG&E tasked with developing smart meter software.[87]

Itron largely avoids the issue of increasing the efficiency of central air conditioning units by stating that the 2006 federal standard for new units is Seasonal Energy Efficiency Ratio (SEER) 13 and the highest SEER rating of "economical" central air conditioning units is 14.[88] Itron goes on to state there is little difference between SEER 13 and SEER 14 in terms of efficiency and therefore no economic justification for upgrading from SEER 13 to SEER 14.

However, the average SEER rating for in-use central air conditioning units in California is approximately SEER 10, not the 2006 federal minimum standard of SEER 13 for new units.[89] Competitively-priced central air conditioning units with ratings as high as SEER 21 are commercially available. As noted below, there is about a 20 percent installed price difference between a SEER 13 or 14 unit and a SEER 21 unit. An incremental energy efficiency improvement of nearly 30 percent is realized by selecting a SEER 21 unit over SEER 13 when compared to the SEER 10 basecase.[90] Itron does acknowledge that major energy efficiency reductions can be achieved in residential and commercial heating and air conditioning systems, though in the context of emerging technology instead of off-the-shelf technology.[91]

Itron also does not address new thermal storage air conditioning systems now on the market which could nearly eliminate cooling-related peak demand if installed in new and existing buildings throughout the region. Graphs of the peak cooling demand reduction achieved by these commercially available thermal storage air conditioning systems are presented in **Attachment H**.

Cost-effective and largely untapped energy efficiency savings can readily be employed on existing commercial and institutional cooling systems as well. Many commercial buildings use electric motor-driven centrifugal chillers to provide cooling. Centrifugal chillers typically consume more electricity than any other single energy-consuming device in a commercial building.[92] The Center for Sustainable Energy has been a leader in conducting energy efficiency evaluations of these cooling systems, conducting hundreds of energy efficiency evaluations on these systems locally. Over 90 percent of these systems operate with relative low efficiency, in the range of 1.0 to 1.2 kW per ton of cooling, using oversized pumps, constant speed equipment, and controls that do not work well.[93,94]

A new trend in these commercial and industrial “chiller plant” cooling systems is converting all devices to variable speed operation and simplified control of the whole system. The initial conversions to this ultra-efficient operating format resulted in an average energy-use reduction of 54 percent over a three-year period.[95] The results indicate that ultra-efficient all-variable-speed systems are reliable and can be installed for the same cost as “standard” central plant systems.

An example of effective application of all-variable-speed operation to an existing chiller plant is the County of San Diego’s North County Regional Center, with 610,000 square feet of air-conditioned space (courthouse, offices, and jail). The retrofit was completed and commissioned in December 2003 at a cost of $423,700. Two years later, the entire plant was averaging less than 0.5 kW per ton, saving the county more than $175,000 a year. The simple payback for this upgrade was less than two-and-a-half years. The North County Regional Center also received a $205,447 incentive payment from SDG&E, reducing the payback period to 1.3 years.[96]

8.2.2 Achieving an Absolute 20 Percent Reduction in Electricity Usage by 2020

Table 8-1 lists a number of the major energy efficiency opportunities that could significantly reduce peak demand and energy consumption in the region. These include upgrades to cooling systems, lighting (phase-out of incandescent bulbs), weatherization, and refrigeration.

Table 8-1. Cost-Effective Energy Efficiency Opportunities in the San Diego Region

Device Type	Sector	Number[97]	Average baseline efficiency	Average age of device (years)	Unit of measure	Target efficiency level	Overall potential reduction versus baseline (%)	Potential peak reduction versus baseline (%)	Estimated payback period for typical installation (years)
Central air conditioning	residential/ small commercial	500,000 – 600,000[98]	10	10.7	SEER[99]	20	50	50	depends on location and use of dynamic pricing[100]
Central air – ice storage	medium and large commercial	22,843	new product	new product	kW per ton	advantage is shifting cooling load to nighttime	no change	80	depends on location and use of dynamic pricing
Central heating/cooling plants	large commercial	689	1.0 – 1.2	unknown	kW per ton	0.5 – 0.7	30 - 50	30 – 50	depends on location and use of dynamic pricing
Central heating/cooling Plants – chilled water storage	large commercial	689	1.0 – 1.2	retrofit	kW per ton	0.5 – 0.7	30 - 50	80	depends on location and use of dynamic pricing
Lighting	residential	1.2 million	10 – 20	1	% CFL[101]	100	~60	~60	< 1
Refrigeration	residential	1.2 million	931[102]	7	kWh/yr	721	20	20	NA - new federal efficiency standard
Weatherization – utility energy conservation upgrade	residential	primarily pre-1990 homes	Title 24 new construction standard [103]	20+	kWh/yr	> 30% from existing condition	30[104]	30	Presumed to be comparable to commercial building payback.
Weatherization – LEED existing building retrofit	commercial, all types	141,200	Title 24 new construction standard	20+	kWh/yr	> 30% from existing condition	30[105]	30	2.6[106]

A 2020 target date to achieve a 20 percent reduction in energy consumption and peak demand would allow time to re-design the current energy efficiency program so that all economically justifiable energy efficiency retrofits are in fact carried-out. This target date would also allow convenient phase-in of long-life high efficiency devices as the original devices reach the end of their useful lives. This is typically in the range of 10 to 15 years for central air conditioning units and 7 to10 years for refrigerators.

Some important actions that would significantly reduce energy consumption in the San Diego area require no action in San Diego other than voicing support. For example, legislation currently in the California Assembly (AB 722, Levine) would ban incandescent bulbs in the residential size range, 25 watts to 150 watts, by 2012. Incandescent bulbs would be replaced principally by compact fluorescent lighting (CFL). CFLs reduce electricity demand 75 percent compared to an incandescent bulb of comparable intensity. Currently only 10 to 20 percent of the light bulbs in California residences are CFLs.[107]

All energy efficiency upgrades with a reasonable energy savings payback period reduce energy costs in SDG&E's service territory. However, it is unlikely that large numbers of individual consumers will be willing to spend significant additional sums of up-front money to maximize the energy efficiency of their residences and businesses. Yet it is in the interest of the community and the region that these residences and businesses are as energy efficient as feasible from a cost perspective.

The utility must fund the difference between the lowest cost, higher energy consuming device and a cost-effective state-of-the-art upgrade if the objective is to realize much of the potential efficiency gains in the region. This is also true of weatherization. The current SDG&E energy efficiency incentives are provided in **Attachment I**. These rebate and incentive payments are modest. No incentive payments are currently offered for central air conditioning system upgrades. The program is far too modest to achieve the energy efficiency targets contemplated for *San Diego Smart Energy 2020*.

Carrier Corporation is a leading provider of central air conditioning systems. The energy demand of a 3-ton Carrier Corporation SEER 10 central air conditioning unit is approximately 4.0 kWh under hot summertime conditions.[108] The company advertises a 56 percent reduction in electricity demand for its Infinity® 21 (SEER 21) model compared to a SEER 10 unit.[109] In an area of the county where air conditioning may be necessary much of the summer, in the range of 800 to 1,000 hours per year, more than 2,000 kWh of energy demand would be eliminated over the course of the summer peak period by selecting the Infinity® 21 for the upgrade.[110]

As noted, the 2006 federal standard for new central air conditioning units is SEER 13. Is it cost-effective to purchase a SEER 21 unit over a SEER 13 unit solely on the basis of energy savings? Yes. The difference in the installed cost prior to rebates of a reference case Carrier Corporation 3-ton SEER 13 residential central air and heating unit, which costs approximately $9,000, and a state-of-the-art Infinity® 21 unit (SEER 21) is around $2,000.[111] Carrier offers a rebate on high efficiency units that reduces the cost difference between the SEER 13 and SEER 21 alternatives. The SEER 21 unit would save approximately 1,200 kWh relative to the SEER 13 unit over 1,000 hours.[112,113] Summer peak savings would be $300 per year, assuming a peak demand rate of $0.25/kWh and smart meters to measure real-time consumption. By way of comparison regarding peak rates, SDG&E is already proposing a critical peak pricing rate of $1.20/kWh for non-residential customers in an effort to reduce peak demand.[114] The simple payback for the $2,000 additional cost of the Infinity® 21 would be 6 to 7 years.

Implementing a cost-effective state-of-the-art requirement for residential central cooling system upgrades would be quite simple in concept. For example, SDG&E would advise local heating and cooling system contractors that the utility will pay the difference between the base price for a central air conditioning system that meets the 2006 federal SEER 13 standard and a state-of-the-art unit (SEER 21 in 2007). SDG&E, or a third party provider such as the Center for Sustainable Energy, would identify each municipality and area in the county where the upgrade is automatic, such as Ramona, Lakeside, Santee, Poway, and El Cajon. The incentive payment in cooler areas of the county where air conditioning systems are run on only the very hottest days, such as La Jolla or Pacific Beach, would be pro-rated to cover the additional cost of the highest SEER rating that is cost-effective based on air conditioning usage patterns in that area.

The conversion to smart meters offers another relatively painless method for dramatically reducing peak load on hot days.[115] There are an estimated 500,000 to 600,000 central air conditioning units in residences in the San Diego region.[116,117] Most or all of these units are in operation on the hottest days of summer. Smart meters with home thermostat control are capable of increasing the set-point room temperature automatically to reduce air conditioning load.

Cycling the set-point of one-half of the central air conditioner population from 72 ^{o}F to 78 ^{o}F for 10 or 15 minutes, and repeating this cycling with the other half of the population for 10 to 15 minutes, would reduce instantaneous MW load during critical peak demand periods by hundreds of MW with almost no impact on the comfort of end users. Residences with sensitive populations, such as the elderly or chronically sick, would be kept out of this type of program. Other customers could opt-out if a compelling reason was provided after the customer had been included in the program for a time and had experienced the impact (or lack of impact) of air conditioning cycling on the comfort level within the residence.

Effective building weatherization is a necessary component of any program intended to minimize the cooling demand. SDG&E has a low-income weatherization program that reached approximately 10,000 homes in 2005.[118] SDG&E reports that the weatherization program elements are cost-effective but does not report the actual reduction in peak electricity demand realized as a result of the program.

However, the City of Houston has published case study data on a 2006 weatherization program conducted in an older neighborhood that resulted in a 14 percent reduction in peak energy demand.[119] Six hundred homes, with an average age of 40 to 60 years in the range of 1,000 to 1,300 square feet, were weatherized. The program was basic. Homes were weatherized with caulking, weatherstripping, and attic insulation of nine inches. The program cost an average of $1,000 per home. Average savings were $160 in the 2006 summer season.

9. Demand Response: Current Utility Program, Pricing and Smart Meters[120]

9.1 Why California is falling short on reducing peak demand

California will fall short of achieving its goal of reducing system peak demand for the three IOUs by 5 percent in the summer of 2007. This goal specifically applies to price response programs that can be called on a day in advance and are designed to address forecasted peaks or supply constraints. Price response programs are likely to reduce peak demand by 2.2 percent, or less than half of the target percentage.

To identify why the state's demand response goals will not be achieved this year, the Brattle Group, which provides consulting services and expert testimony in economics, finance and regulation, interviewed two dozen stakeholders within and outside of California. Several reasons for not meeting the demand response goals emerged.

First, the goals focused solely on price response programs, which require advanced interval meters. When the goals were set, only customers with greater than 200 kW demand, representing about one-fourth of the system peak load, had these meters. Achieving the 5 percent goal from large customers alone requires that they reduce their peak demand by about 20 percent.

Second, even by 2011, when advanced metering infrastructure will be installed for customers under 200 kW, a large portion of the electricity consumption in the commercial customer class with demand under 200 kW will continue to be protected from rate changes by AB 1X. This protection may last through the year 2021.

Large customers already face time-of-use (TOU) rates that charge higher prices for demand during peak periods. Many of the largest customers have been on TOU for years. Over 23,000 advanced interval meters were installed for customers with greater than 200 kW of demand as a result of AB 29X. The legislation required that all meter recipients shift to TOU rates. Much of the potential for peak load reduction from the largest commercial customers has already been realized as they have adapted their operations to higher peak prices.

The utilities have proposed voluntary critical peak pricing rates and peak time rebates to accommodate the AB 1X provisions. However, the true potential for demand response from commercial customers is unlikely to be achieved due to a combination of complications. For example, there is currently a built-in disincentive to customers with average demand under 200 kW and with a high peak demand to leave a program, AB 1X, that protects these customers from rate spikes.

The current approach appears to be too centered on the utility and may need to be replaced with an approach focused on customer needs and infrastructure constraints. California lags behind states with restructured power markets where all large customers above 1 MW face default hourly real-time pricing tariffs. Most regions with active demand response programs have both “day ahead” and “day of” programs using a combination of pricing and rebate payments to encourage customers to lower peak loads and/or shift load to off-peak periods.

9.2 Steps necessary to get more from demand response

Rate and program designs must be developed that better reflect the value of demand response to the electricity system and the value of consumption to customers. California has pursued its energy efficiency goals through a combination of programs and standards. At least half of the efficiency gains that have been realized since 1975 have been due to standards. Now may be the time to examine the potential for using standards to achieve the state's demand response goals.

Cost-benefit methodologies for evaluating demand-side programs need to be improved. Protocols must be developed for measuring demand response impacts. Innovative rate designs are needed that incorporate the risks of outages and high peak generation costs.

Dynamic rate designs and effective protocols for measuring demand response impacts are steps toward solving these problems. There is a need to better educate customers about the costs embodied in current rates, the benefits that could come from broad adoption of dynamic rates, the true impacts on their electricity costs that would result from such a change, and the options they have for responding.

Many customers assume such rates would amount to rate increases when in fact utility revenue would not change. Customers whose consumption patterns reflect below average peak consumption would see bill reductions. Those with above average peak consumption would see increases that reflect the degree to which their peak consumption is currently receiving a hidden subsidy from other customers.

9.3 Smart meters are a part of the solution

The demand for electricity is highly concentrated in the top 1 percent of hours of the year. In most parts of the United States, these 80 to 100 hours account for roughly 8 to 12 percent of the maximum or peak demand. In California, they account for approximately 11 percent.

If a way can be found to reduce some of this peak demand, it would eliminate the need to install generation capacity that would be used less than 100 hours a year. This generating capacity is primarily gas-fired peaking combustion turbines. This is expensive power generation given these turbines are idle for almost all of the year.

How much will be saved by demand response will depend on two issues: 1) how much peak load can be reduced by customers and 2) how much generation (and related power delivery) investment and fuel can be offset by this load reduction. The first item depends on two things: how rapidly utilities and regulators move to install new pricing designs that provide the correct price signals to customers, and how well customers respond to the price signals.

A prerequisite to the provision of dynamic pricing is the installation of Advanced Metering Infrastructure (AMI). Depending on features and geography, AMI investment costs can range from $100 to $200 per meter. Much of that cost can be recovered through operational benefits such as avoided meter reading costs, faster outage detection, improved customer service, better management of customer connects and disconnects, and improved distribution management.

Many utilities have already installed AMI because they were able to recover their entire investment through operational benefits. According to a recent Federal Energy Regulatory Commission report, AMI currently reaches 6 percent of electric meters in the United States. Certain states, such as Pennsylvania and Wisconsin, have AMI penetration rates in excess of 40 percent. AMI penetration rates are in the double digits in eight states.[121]

California's three IOUs tested a variety of dynamic pricing designs in a $20 million pilot project that involved approximately 2,500 residential and small commercial and industrial customers over a three-year period. The experimental process involved a working group that was facilitated by the CPUC and CEC and many interested parties, some opposed to dynamic pricing and some supporting it.

The California experiment provided time-varying prices and smart meters to all participants. In addition, some of the participants also received enabling technologies such as smart thermostats and always-on gateway systems. Smart thermostats automatically raise the temperature setting on the thermostat by 2 or 4 degrees when the price becomes critical. Always-on gateway systems adjust the usage of multiple appliances in a similar fashion and represent the state-of-the art.

The experiment showed that the average Californian customer reduced demand during the top 60 summer hours by 13 percent in response to dynamic pricing signals that were 5 times higher than their standard tariff. Customers who had a smart thermostat reduced their load about twice as much, by 27 percent. And those who had the gateway system reduced their load by 43 percent. The AMI meters that SDG&E will install will be capable of supporting smart thermostat controls and gateway systems.

The gateway "smart meter" system represents the maximum technical potential for demand reduction in the residential customer class. The smart meter system has the potential for lowering peak demand by 43 percent. In the commercial and industrial classes, automatic demand response programs that control multiple end-use loads while working with the energy management system that is installed in most facilities are projected to reduce demand by 13 percent. The weighted average technical demand response potential for all classes is estimated at approximately 23 percent.

The peak demand in SDG&E service territory in 2007 was 4,636 MW. A 23 percent reduction in 2007 peak demand through use of smart meters represents a demand reduction of approximately 1,070 MW. SDG&E estimates that the use of smart meters in SDG&E territory will result in a 5 percent reduction of peak demand 2016, a forecast demand reduction of 249 MW.[122]

10. San Diego Solar Initiative: Cost-Effective Regional Photovoltaics

10.1 Design of California Solar Initiative

The SB1 "million solar roofs" legislation has established the objective of adding 3,000 MW of commercial and residential PV installations in California by 2017. SDG&E serves approximately 10 percent of the IOU customer base in California, and for that reason it is assumed that 300 MW of this PV capacity will be added in SDG&E service territory.[123] $3.35 billion in incentives will be paid-out over the course of the 10-year program. The objective of these incentive payments, in combination with federal and state tax incentives, is to make PV cost-competitive with purchased utility power.

The 12 kW system example shown in Table 10-1 demonstrates the financial impact of the incentive payment and tax credits on the net cost of the PV system. The 12 kW system used in the example is presumed to be a system installed on a residence under a commercial third party power purchase agreement structure.

Table 10-1. Net Cost of 12 kW PV System under SB1 California Solar Initiative[124]

Cost or (Credit), $	Cost Element
100,000	gross cost of 12 kW PV system @ approximately $8 per installed watt
(15,000)	net CSI incentive payment, gross incentive of $25,000 less income tax paid of $10,000
(30,000)	30 percent federal tax credit on gross cost
(28,000)	depreciation on gross cost less tax credit ($70,000 × tax rate)
27,000	net cost of PV system

The annual loan payment would be $2,500 per year, assuming the net capital cost of $27,000 is amortized at 7 percent interest over 20 years. This system would be expected to generate approximately 1,550 kWh per year kW installed, or 1,550 kW × 12 kW = 18,600 kWh per year. Dividing the annual cost of $2,500 by the annual power production of 18,600 kWh gives a unit electricity generation cost of $0.135/kWh. This compares to a typical current SDG&E electric energy charge of $0.15 to $0.25/kWh for residential customers.[125]

Commercial PV systems rely on the incentives, tax credits, and depreciation shown in Table 10-1 to produce electricity that is competitive with utility electricity rates. The major program under SB1 is the California Solar Initiative (CSI). CSI has a $2.165 billion incentives budget and a goal of 1,940 MW of new PV capacity by 2017. The CSI program provides performance-based incentive payments for each kWh produced from commercial PV systems instead of a flat initial payment for smaller systems that is based on the size of the PV system.

The fundamental concept behind the CSI program is that a large increase in demand for PV systems will steadily reduce the cost of PV to the point where PV technology will be cost-competitive with purchased utility electricity rates by 2017 without incentive payments (though assuming federal and state tax credits remain). Expectations of large growth in PV capacity are predicated on the cost of PV steadily dropping over the next decade to half the current cost due in part to the large demand increase created by the CSI incentives.

Favorable utility tariffs will play an important role in driving the expanded use of PV in commercial systems as well. Most of the initial CSI incentives for commercial PV systems went to applicants in PG&E service territory, in part because of a favorable rate structure for PV systems. This rate structure, known as the A-6 tariff, pays nearly triple the proposed SDG&E rate for commercial solar power.[126] The PG&E and SDG&E rate structures for commercial solar installations are compared in Table 10-2. A SDG&E commercial solar tariff structure that is comparable to the PG&E tariff would allow commercial PV in SDG&E service territory to compete on a level playing field for statewide incentive payments under CSI.

Table 10-2. Comparison of PG&E and SDG&E Commercial PV Rate Structures

	PG&E A-6 tariff	SDG&E AL-TOU tariff (proposed)[127]
Energy Charges ($/kWh)		
Summer		
Peak	0.319	0.109
Part-peak	0.157	0.092
Off-peak	0.093	0.073
Winter		
Peak		0.108
Part-peak	0.138	0.100
Off-peak	0.102	0.079
Demand Charges ($/kW)		
Facility charges	none	10.70
Summer peak	none	4.72
Winter	none	3.59

10.2 Proposed San Diego Solar Initiative

10.2.1 Achieving 50 Percent Greenhouse Gas Reduction with Photovoltaics

A primary goal of *San Diego Smart Energy 2020* is to reduce greenhouse gas emissions from power generation serving San Diego County customers as rapidly as cost-effectively feasible. Accelerated use energy efficiency measures and renewable energy will be necessary to achieve this goal. The *Regional Energy Strategy 2030* establishes a goal of 50 percent of the renewable energy used in the region coming from local renewable energy resources. The large majority of the renewable resources that SDG&E is proposing to utilize to meet the SB 107 “20 percent by 2010” renewable energy mandate, primarily biomass, wind, geothermal, and solar power, will be imported from other regions.

The most abundant renewable resource in San Diego County is the sun. San Diego County currently has approximately 38 MW of installed commercial and residential PV capacity. San Diego County also has thousands of MW of PV potential on existing commercial buildings, parking lots and parking structures, and residences. Rooftop PV has the advantage of being relatively non-controversial from a siting standpoint. The City of San Diego and San Diego Schools pay less per kWh for PV power purchased from third party providers than the energy charge they would otherwise pay SDG&E for the same power generated by conventional power plants. This is possible under the current matrix of PV incentives, tax credits, and depreciation that apply to these PV systems.

For these reasons, the renewable energy component of *San Diego Smart Energy 2020* is focused on local rooftop PV, primarily commercial installations, to expand the renewable energy component of the power used by San Diego County businesses and residences from 20 percent in 2010 to 50 percent in 2020. PV is arguably the best renewable energy “fit” for San Diego County, due primarily to the fact that PV is generated at the point of use and is generally operating at or near capacity when electric power is most needed and most valuable. This is especially true if the PV systems are equipped with adequate battery storage to operate as reliable peaking power units during summertime afternoon peak demand periods.

The renewable energy component of *San Diego Smart Energy 2020* would require the addition of just over 2,000 MW of PV by 2020 to achieve a 50 percent GHG reduction from electric power generation. A leading developer of commercial solar PV was contacted by Powers Engineering to provide an estimate of the incentives budget necessary to cost-effectively meet this PV target by 2020. “Cost-effective” in this case means a payback in approximately 10 years for a commercial PV system in a market where the benchmark utility electric rate is $0.12/kWh.The estimated life-of-project PV incentives budget to achieve this goal is estimated at $1.5 billion (in 2007 dollars).[128] All of this $1.5 billion incentive budget would be utilized to build renewable PV distributed generation in the San Diego region. The *San Diego Solar Initiative* is an appropriate name for this PV program.

The *San Diego Solar Initiative* would be far less expensive than the proposed SPL transmission project over time. The capital cost estimated by SDG&E for its portion of the transmission project is $1.265 billion. The estimated total cost over the 40-year project lifetime, including SDG&E profit, is approximately $7 billion in 2010 dollars.[129] A recent proposal by SDG&E to underground the transmission line between Lake Henshaw and Santa Ysabel could add up to another $300 million to the capital cost, increasing the estimate to $1.565 billion.[130] This would in turn increase the levelized cost of the project over 40 years from $7 billion to $8.3 billion.

The cost to build transmission lines is also rising rapidly in general. A recent report prepared by the Brattle Group for the Edison Foundation states that price increases in the past several years have affected all utility sector investments from coal and wind power projects to transmission and distribution projects. Between January 2004 and January 2007, the costs of steam-generation plants, transmission projects, and distribution equipment rose by 25 to 35 percent (compared with an 8 percent rise in the overall price level). The coauthor of the report noted that if these cost increases persist, they will confront utilities and regulators with even tougher choices on capital investment plans in the future, and motivate stepped-up conservation and demand-side programs.[131]

The levelized annual cost of the proposed SPL transmission project, in 2006 dollars, is $174 million per year for 40 years. This expenditure would provide 1,000 MW of additional import capacity to the San Diego region. However, there is no assurance that there will be power to import over the line during periods of peak regional demand. For example, the California Independent System Operator (CAISO) declared a statewide Stage 1 electrical emergency on August 29, 2007 from 3:20 pm to 8:00 pm. A Stage 1 emergency designation is a call for voluntary conservation. The Stage 1 press release issued by CAISO stated a primary reason for the Stage 1 emergency was, "*temperatures throughout the Southwest continue to climb, decreasing the availability of imported power*."[132] The existence of transmission capacity does not assure that the transmission capacity can be utilized during periods of peak demand if electricity demand is peaking throughout the region at the same time.

The $1.5 billion incentives budget under the *San Diego Solar Initiative* would total $1.5 billion over 20 years in current dollars. The average annual cost of the *San Diego Solar Initiative*, in 2007 dollars, would be $76 million per year over the 20-year life of the incentive payment program, less than one-half the cost of the SPL over the same time period. The distribution of the $1.5 billion in PV incentives is shown in the PV incentive program financing plan summary tables included in **Attachment J**.

The $1.5 billion budget would incentivize the installation of 2,040 MW of commercial PV (primarily) in the San Diego region by 2020. This PV capacity will be equipped with sufficient battery storage so that it can reliably serve the afternoon peak load at rated output. This capacity is in addition to the 300 MW of PV that will be installed in SDG&E service territory by 2017 as a result of SB1.

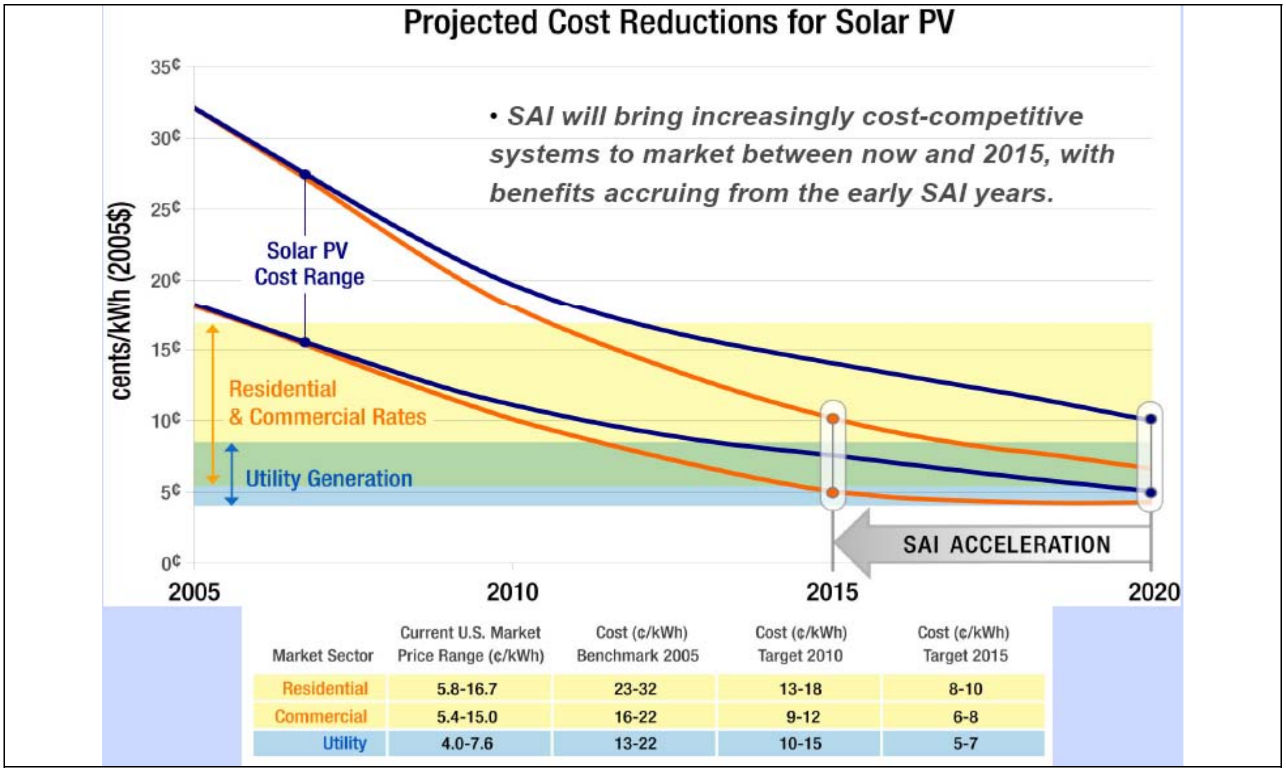
The assumptions behind this addition of 2,040 MW by 2020 are that current federal tax credits and accelerated depreciation remain in place, and customers pay a third party provider $0.12/kWh for the PV energy. Additional assumptions are that the majority of the installed capacity, approximately 75 percent, will be commercial installations over 100 kW, and that a high level of standardization will be utilized by a limited number of large contractors to minimize costs through bulk purchasing of PV system hardware.

Achieving the goal of 2,040 MW installed by 2020 under the *San Diego Solar Initiative* is also based on the installed cost of PV systems dropping by approximately 40 percent between 2008 and 2017. The *San Diego Solar Initiative* would be a major PV incentive program in addition to SB1, accelerating the decline in PV cost relative to conventional power generation. The current installed cost of residential rooftop PV systems is approximately $8 per watt prior to incentive payments and tax credits (see Table 10-1). The cost is 10 to 15 percent lower for large wholesale buyers of PV panels and associated hardware.[133]

This projected decline in the cost of PV systems is conservative relative to U.S. Department of Energy (DOE) projections and current industry trends. Figure 10-1 is a DOE projection of the decline in PV costs through 2020. DOE estimates PV will reach cost parity with high cost conventional baseload power generation by 2020 under a "business as usual" scenario. The

CPUC now limits utility baseload long-term power contracts to sources with a GHG footprint of a natural gas-fired combined cycle power plant. This is high-cost baseload power generation in a time when natural gas averages $7 per million Btu or more. According to DOE, cost parity will be reached by 2015 if PV is incentivized to ensure a large and growing market over the next decade. See the lower curve in Figure 10-1.

Figure 10-1. DOE Projection of Decline in PV Cost Through 2020[134]



Market Sector	Current U.S. Market Price Range (¢/kWh)	Cost (¢/kWh) Benchmark 2005	Cost (¢/kWh) Target 2010	Cost (¢/kWh) Target 2015
Residential	5.8-16.7	23-32	13-18	8-10
Commercial	5.4-15.0	16-22	9-12	6-8
Utility	4.0-7.6	13-22	10-15	5-7

There are currently limits on the availability of PV panels. However, a very rapid expansion of PV manufacturing capacity is underway. Worldwide PV manufacturing capacity expanded 41 percent in 2006. Production is currently constrained by a shortage of manufacturing capacity. However, more than a dozen companies in Europe, China, Japan, and the U.S. will bring unprecedented levels of production capacity online in the next two years, reversing manufacturing constraints. The PV industry estimates the cost of PV will decline 40 percent by 2010 as a result of this tremendous expansion in PV production capacity.[135]

The 2,040 MW of PV to be added under the *San Diego Solar Initiative* would be equipped with sufficient battery storage, equivalent to 2 to 3 hours of rated capacity, to enable this PV capacity to be dispatchable during the late afternoon peak. 2,040 MW of PV capacity would meet more than half of San Diego County's projected peak demand (under *San Diego Smart Energy 2020*) of 3,500 MW in 2020.

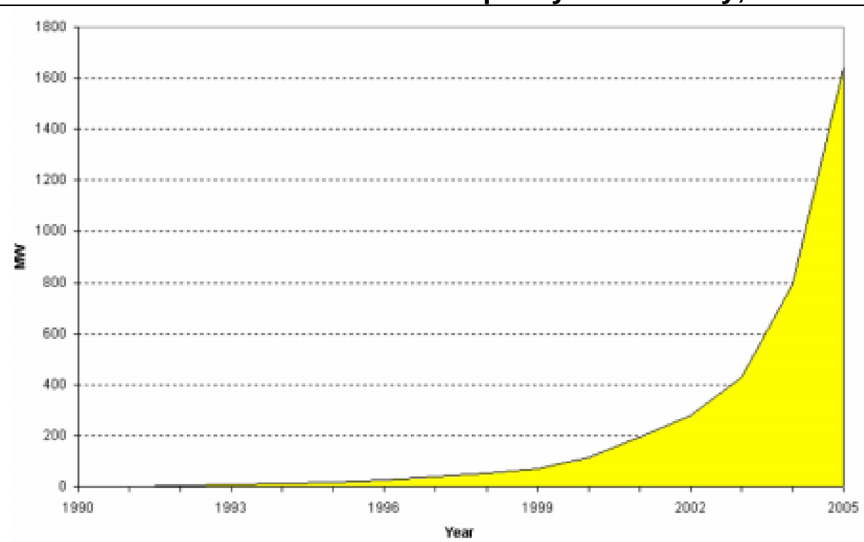
PV systems provide peak power output in the middle of the day, yet peak demand is generally later in the afternoon, typically 3 pm to 6 pm. The CEC is funding a demonstration in Southern California Edison territory of sophisticated energy management/battery systems integrated with residential PV to serve as peaking units to meet the late afternoon summertime peak.[136] The energy management/battery systems are fully controllable by the utility as peaking units. The addition of energy management and battery storage allows the PV system to supply the utility grid with its rated output through the late afternoon summertime demand peak. The energy management/battery system adds approximately 10 percent to the cost of the PV system.[137]

The San Diego region is projected to have approximately 4,600 MW of PV technical potential on commercial buildings, parking structures, and parking lots in 2010, as well as 2,800 MW of technical potential on residential structures.[138] The 2,040 MW PV target will be developed from this 7,400 MW of PV technical resource base.

The annual energy production of this PV capacity developed under the *San Diego Solar Initiative* will be approximately 25 percent of the region's annual energy demand in 2020. SDG&E is obligated by SB 107 to obtain 20 percent of its power sales from renewable energy sources by 2010. An assumption in *San Diego Smart Energy 2020* is that the energy generated by these renewable energy contracts, 3,500 GWh per year, continues to be produced at the 3,500 GWh per year level for the foreseeable future. 3,500 GWh per year will be approximately 22 percent of total energy demand in 2020. The 300 MW of regional PV added under SB1 will supply 3 percent of total energy demand. Combined, these renewable energy sources will provide 50 percent of the region's annual energy demand in 2020.

The *San Diego Solar Initiative* would follow a development curve, in terms of rate of growth in installed PV power, similar to the rate-of-growth demonstrated in the German PV program. The German PV program reached a growth rate of 837 MW per year in 2005. See Figure 10-2. The *San Diego Solar Initiative* would start gradually and finish fast. Approximately 40 MW would be installed in 2008-2010, the first three years of the *Initiative*. 2,040 MW would be in operation by 2020.

Figure 10-2. Total Installed Solar PV Capacity in Germany, 1990 - 2005[139]



10.2.2 Greenhouse Gas Reduction Achievable with $700 Million Photovoltaics Incentive Budget

California utilities have historically been responsible for recovering 100 percent of the cost of their transmission investments from their own ratepayers. However in 2000 the Federal Energy Regulatory Commission instituted a new cost allocation procedure for transmission projects.[140] Transmission costs for such projects are now borne proportionately by the state's three regulated utilities, SCE, PG&E, and SDG&E, regardless of the utility territory where the project is actually located. The SDG&E customer base represents approximately 10 percent of the customer base of the three utilities combined. As a result, even though the cost of SPL will be $7 billion to $8.3 billion (2010 dollars) over the financial life of the project, SDG&E customers will pay only 10 percent of this cost, $700 to $830 million, over the 40-year financial life of SPL. SDG&E customers also pay 10 percent of SCE and PG&E transmission projects.

As noted, under the current rules of transmission line cost allocation, SDG&E customers will pay $700 to $830 million of the total cost. It is therefore of value to determine how much PV could be installed in the San Diego County area with an incentive budget of $700 to $830 million, given that is the amount that these SDG&E ratepayers will be charged for the SPL.

A $700 million budget would incentivize the installation of 1,030 MW of PV without battery storage in the San Diego region by 2020. Assuming 10 percent of the $700 million incentive budget is used for energy management/battery systems and the remaining 90 percent for PV capacity, approximately 920 MW of PV capacity would be installed that is capable of operating at rated output throughout the afternoon 3 pm to 6 pm peak summertime demand period. An $830 million budget would incentivize the installation of 1,220 MW of PV without battery storage, and 1,100 MW with battery storage to maintain rated output through the afternoon peak. The distribution of the $700 million in PV incentives is shown in the PV incentive program financing plan summary tables included in **Attachment K**.

How does this projection compare to the projection for the CSI program? The objective of the CSI $2.165 billion incentive budget is to increase installed PV capacity in California to 1,940 MW by 2017. A $700 million incentive budget is one-third the CSI incentive budget of $2.165 billion. The approximate installed PV capacity that could be expected from a $700 million incentive budget under CSI would be in the range of 650 MW (without battery storage), one-third the CSI target of 1,940 MW.

10.2.3. Displacement of PV with Concentrating Solar and Wind

The overall cost of the renewable energy portfolio to achieve 50 percent greenhouse gas reduction by 2020 will decline to the degree that renewable energy parks develop in the more rural areas of San Diego County, using concentrating PV or a concentrating solar technology of similar efficiency, and these parks displace a portion of the 2,040 MW of fixed PV capacity that would result from the *San Diego Solar Initiative*. These renewable energy parks are discussed in more detail in Section 13. To the degree that wind power substitutes for this fixed PV capacity, assuming no new transmission must be built to accommodate that wind power, the cost to achieve the 50 percent greenhouse gas reduction by 2020 will drop further. Regional wind power is discussed in more detail in Section 14.

10.3 Coordinating PV Installations with Roof Replacements

Commercial and residential PV installations can be coordinated with roof replacements to maximize efficiencies. The typical service life of roofing material is 20 to 25 years. The typical guarantee period for solar panels is 25 years. Timing the PV installation with a new roof means the entire roof and PV system will have a coordinated minimum service life in the range of 25 years.

San Diego City Schools contracted the integrated re-roofing and installation of a total of 5,110 kW of PV power on fourteen schools to Solar Integrated, Inc. (Los Angeles). The contractual arrangement is a long-term power purchase agreement, where Solar Integrated owns the roofs and the PV panels. Solar Integrated manufactures the high efficiency "cool roof" (http://www.solarintegrated.com/non_pv.htm) and adds PV as a component of the roof installation.

City Schools is charged a fixed $/kWh rate for all PV power generated. This rate is significantly below the rate City Schools would otherwise pay SDG&E for utility power.[141] This is one example of a relatively painless financing and ownership model that could be employed at hundreds of commercial sites in the San Diego region if an adequate incentive budget is available. Figure 10-3 shows the San Diego Education Center equipped with a cool roof and 100 kW of rooftop PV.

Figure 10-3. San Diego Education Center with High Efficiency Roof and PV

11. Renewable Energy Tariffs: The Key is Rates that Reflect Actual Value

A fundamental assumption of SB1 and the proposed *San Diego Solar Initiative* programs is that PV costs will decline steadily over the next decade, to the point that PV will compete without incentives against natural gas-fired generation. However, there are other proven financing mechanisms available to achieve rapid renewable energy development. One of these mechanisms is a "standard offer" for this renewable power offered by the utilities that is sufficiently generous that the renewable energy power producer receives a fair return on the renewable power investment.

The use of standard offer prices for renewable energy projects is a proven model for assuring the financing of innovative renewable energy projects. Thousands of MW of renewable wind, solar, and geothermal projects were built in California in the 1980s as a direct result of the standard offer contract structure. This is the format used in the San Diego region with "qualifying facilities," larger cogeneration plants that produce steam from industrial or commercial use and power primarily (though not exclusively) for export to SDG&E.

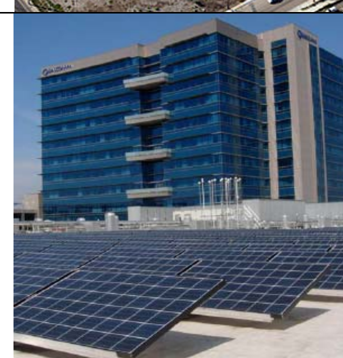
Last year 10,000 MW of wind power were installed in Europe, primarily in countries with feed-in tariffs. "Feed-in tariff" means the renewable energy producer is paid a fixed rate for the renewable power sold to the grid.

Renewable energy development in the U.S. is contingent on the federal production tax credit at present. This program has been essential in the U.S. for promoting wind power. However, it has also suffered from three principal drawbacks. First, it has been an "on again, off again" tax credit, subjecting the industry to boom and bust cycles. Second, the credit originally only applied to wind, though it was extended to other types of renewable energy in the 2005 Energy Policy Act. The two-year cycle of expiration of this tax credit creates a challenging timeframe for renewable projects other than wind. Third, it only supports projects for the first 10 years, making it less helpful than the German solar tariff which pays projects for 20 years. Twenty years is much closer to a realistic financial lifecycle for solar projects. Fourth, it only applies to commercial (private) developers who can take tax credits. Government agencies, municipal utilities like Los Angeles Department of Water and Power and Imperial Irrigation District and other non-profit entities, are ineligible.

In Europe, feed-in tariffs are set either at a fixed price, or a fixed premium above spot market prices. Price levels and premiums vary by technology, reflecting variation in technology costs. Incentives vary by country. Incentives for some technologies are scheduled to decline over time. California is currently implementing two programs with incentives similar to feed-in tariffs. As part of the CSI, the CPUC has developed performance-based incentives with set payments per kWh for qualifying solar photovoltaic systems. The CPUC is also implementing a process to determine a tariff rate that will be offered to public water or wastewater agencies for renewable generation and whether this or a similar tariff should be used to spur additional renewable resource development.

The renewable energy payments need to be fully justifiable based upon a real mix of value factors, so it is not in fact or perception a subsidy or special handout. This is the foundation for the German feed-in tariff for solar energy. The German government calculated how much solar peak energy was worth, adding up the electric value, the social value, the environmental value, and the future risk hedge value. The feed-in tariff is not a charity payment, but a payment for real value delivered. European countries that do not set tariffs high enough have not been nearly as successful as those with fixed, long-term rates that are reasonably generous.

12. Approaching Carbon Neutral Now: Local Examples of Cutting-Edge Facilities

San Diego City Schools, 5,110 kW of PV: Photo at right is the roof of the Juarez Elementary school. The PV output from this installation is 67 kW. City Schools has a long-term power purchase agreement with Solar Integrated (Los Angeles). A total of 14 schools have been re-roofed using high efficiency “cool roofs” that serve as a platform for the PV arrays. Solar Integrated owns and maintains the roofs and the PV systems. City Schools pays a flat $/kWh rate for the power generated by the PV systems. This rate is significantly below the rate City Schools would otherwise pay SDG&E for electricity.	
City of San Diego, Alvarado Water Treatment Plant: This 945 kW PV system was built via a long-term power purchase agreement with SunEdison. The city pays SunEdison $0.12/kWh, offsetting a current utility rate of approximately $0.17/kWh.	
Qualcomm Building W Campus, Sorrento Valley: The 250 kW PV array is installed on the roof of the building and the shade structure of the parking garage. The PV output is sufficient to support all lighting requirements for the building, parking structure and onsite cogeneration plant. Efficiency improvements, including high efficiency lighting fixtures, gas absorption chillers, boilers, and water heaters, have combined to reduce electricity consumption by 30 percent.	
Solara housing complex, Poway: This housing complex is the first of its kind in the state - a green-built, government-financed, affordable-housing complex that is nearly climate neutral, constructed with minimum pollution and maximum energy efficiency. The California Energy Commission subsidized the $18.5 million Solara complex to help create a working example for developers in the public and private sectors on how to build green and at low cost.	
Kyocera parking lot, Kearny Mesa: The 235 kW “solar grove” arrangement provides PV electricity to the adjacent manufacturing plant as well as shade and cover for autos in the parking lot. EnvisionSolar, a San Diego company, is now marketing solar PV systems for parking areas.	

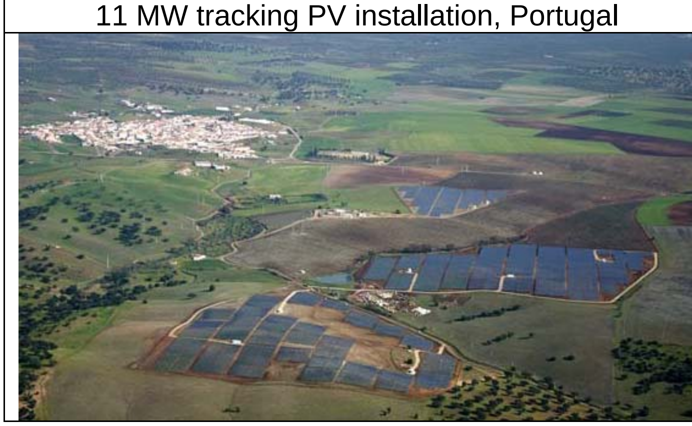
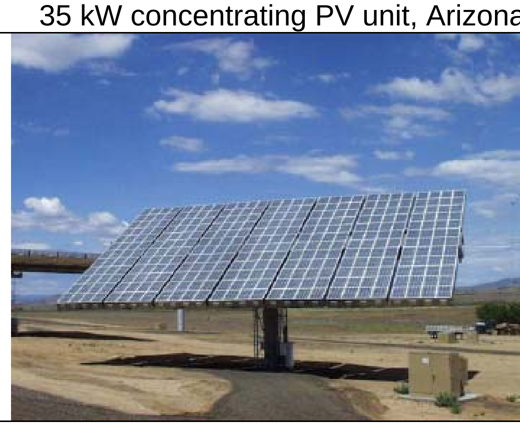
13. Concentrating Solar and Renewable Energy Parks

San Diego County is rich in solar resources. Use of concentrating solar technologies, as opposed to fixed rooftop PV, can maximize the amount of solar energy extracted from this solar resource. There are four types of concentrating solar technologies in operation or under development at this time: 1) solar trough, 2) concentrating PV, 3) dish Stirling, and 4) concentrating towers. Although not a concentrating solar technology, tracking PV has been deployed on a large scale and is fully commercial. “Tracking” means the panel or dish slowly pivots to follow the path of the sun over the course of the day. A tracking PV system generates significantly more power than a fixed PV system as a result.

Solar trough is the only concentrating solar technology that can be considered fully commercial at this time, with 354 MW of capacity in operation in California. The minimum size considered commercially viable for this technology is approximately 50 MW. A 50 MW solar trough power plant would require approximately 300 acres of flat land. As a result, solar trough technology is not a good match for the terrain or land availability realities of San Diego County.

Dish Stirling and concentrating tower technologies are still at a pre-commercial stage.[142] The San Diego Regional Renewable Energy Study Group addressed dish Stirling in its August 2005 report *Potential for Renewable Energy in the San Diego Region*.[143] Dish/Stirling is identified as pre-commercial in this study, based on analyses conducted by the National Renewable Energy Laboratory and Black & Veatch consulting engineering firm. In contrast, concentrating PV has performed well at the 1 MW pilot stage and appears ready for commercial scale-up to a 5 to 10 MW size.[144] PG&E has announced a contract for a 2 MW concentrating PV peaking power plant on 8 acres in Tracy, California.[145] Tracking PV systems are also commercial and have been built as large as 11 MW. Photos of an 11 MW tracking PV array in Portugal, and of a concentrating PV unit operating in Arizona, are provided in Figure 13-1. PG&E has also announced an agreement for 5 MW of PV on 40 acres near PG&E’s Mendota substation in Fresno County.[146]

Figure 13-1. Tracking PV Array and Concentrating PV Unit

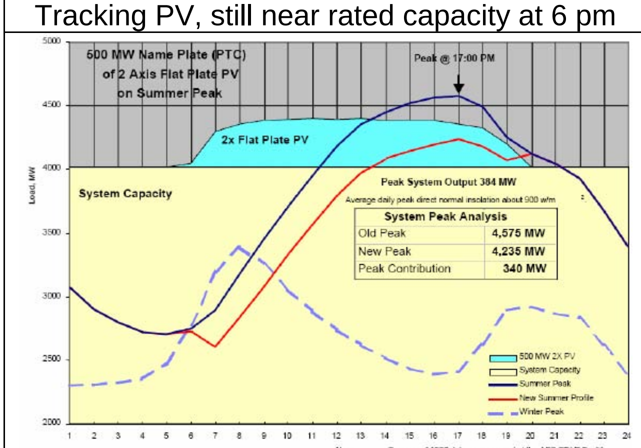
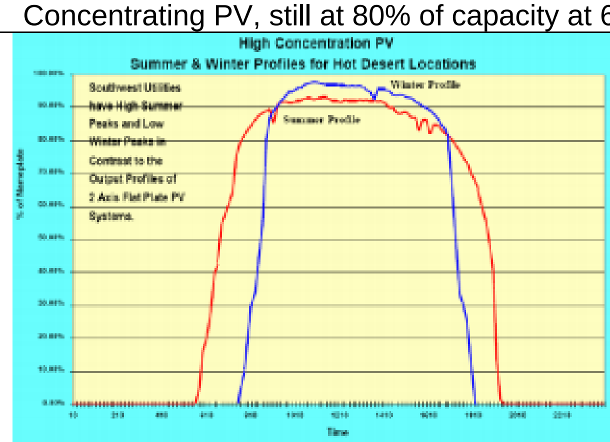
11 MW tracking PV installation, Portugal	35 kW concentrating PV unit, Arizona
	

San Diego County has few areas that are amenable to the land requirements necessary for a commercial-scale solar trough power plant. To address this reality, the concept of “renewable energy parks" has been developed to best match the topography and land use of more rural areas of San Diego County with appropriate solar options.[147] This concept entails the deployment of many smaller concentrating PV or tracking PV arrays in the 1 to 10 MW size on commercially-available land near existing SDG&E transmission lines and substations. SDG&E owns a network of 69 kV transmission lines that serve the rural areas of the county. Power from these renewable energy parks would be delivered over the 69 kV grid to developed areas of the county.

A credible and inclusive stakeholder process will be necessary to establish ground rules for identifying acceptable renewable energy park parcels. Many of the residents and landowners in the backcountry of San Diego County are there because it is rural and relatively undeveloped and would prefer that it remain that way. These are the people that will be most directly impacted by the renewable energy parks. However, many of these same residents are aware of the need to move quickly to address climate change and greatly increase renewable energy production. The inclusive stakeholder process used to develop the *RES 2030* is an example of the type of stakeholder process that could be used to cooperatively identify the most suitable sites for renewable energy parks. Without such a stakeholder process, the development of renewable energy parks in the backcountry will almost certainly experience delays and unnecessary controversy.

The power generation profile of concentrating PV and tracking PV closely match the daily power demand profile. See Figure 13-2. As a result, both of these technologies are good candidates to serve as peaking power supplies on hot summer days. The CEC recently compared the lifecycle cost of a host of power generation technologies and determined the lifecycle cost of power generation from concentrating PV is considerably lower than the cost of generation from a peaking gas turbine.[148] This further reinforces the advisability of the development of a renewable energy park using concentrating PV or tracking PV to demonstrate that such installations can serve as reliable peaking units on the hottest summer days (when the sun is always shining).

Figure 13-2. Daily Power Generation Profiles of Concentrating PV and Tracking PV

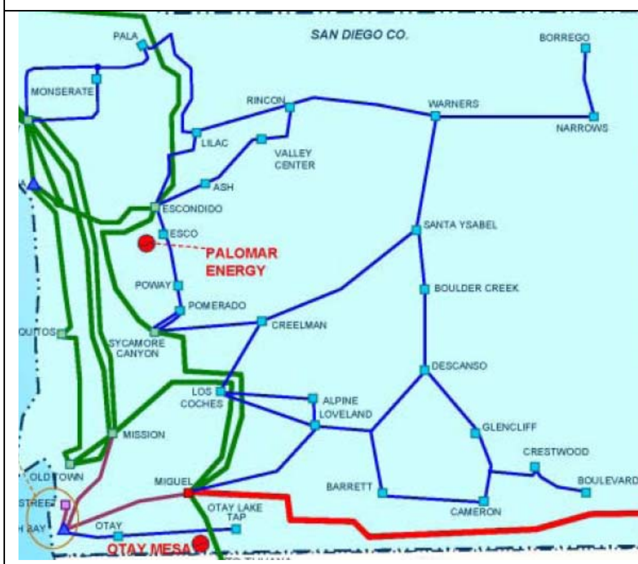
Tracking PV, still near rated capacity at 6 pm	Concentrating PV, still at 80% of capacity at 6 pm
	

The existing 69 kV system should be capable of handling hundreds of MW of power generation from individual 1 to 10 MW solar installations in rural areas of the county. Should these renewable parks develop rapidly, the capacity of the 69 kV system can be approximately doubled by reconductoring the existing lines with commercially available high temperature, low sag conductor technology. The location of these 69 kV lines is shown in Figure 13-3a. The capacity of the 69 kV system in East County, which consists of four separate existing 69 kV lines, could be increased to the range of up to 1,000 MW total via reconductoring and transformer substation upgrades.[149] Increasing the voltage of the 69 kV grid would also be a consideration if growth of the renewable parks began to approach the capacity of an upgraded 69 kV system. Reconductoring with high temperature, low sag conductors is also an option for transmission lines with voltages up to 230 kV.

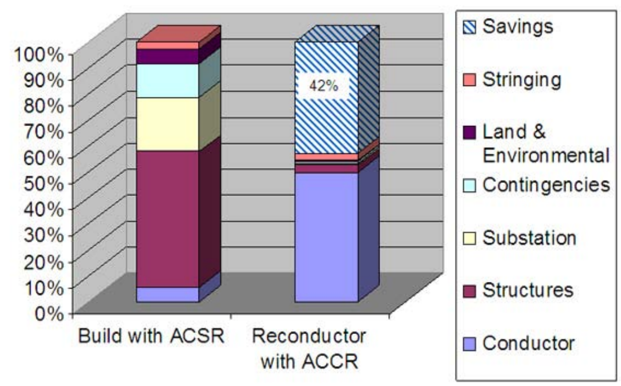
One type of high temperature, low sag conductor is manufactured by 3M Company. SDG&E has a test section of the 3M high temperature, low sag conductor on an existing 69 kV line.[150] According to data provided by 3M, it is significantly less expensive to replace the wire on an existing 69 kV line with this type of high temperature, low sag conductor than to build a new 69 kV line. The relative cost of reconductoring an existing 69 kV line compared to a new 69 kV line is shown in Figure 13-3b.

Figure 13-3. Existing SDG&E 69 kV Grid and Relative Cost of a New Stand-Alone Transmission Line Versus Reconductoring with Composite Line to Double Capacity[151,152]

a. Existing SDG&E transmission lines: 69 kV (blue), 230 kV (green), and 500 kV (red)



b. Reconductoring versus new conventional transmission line to achieve same capacity increase: 42 percent cost savings



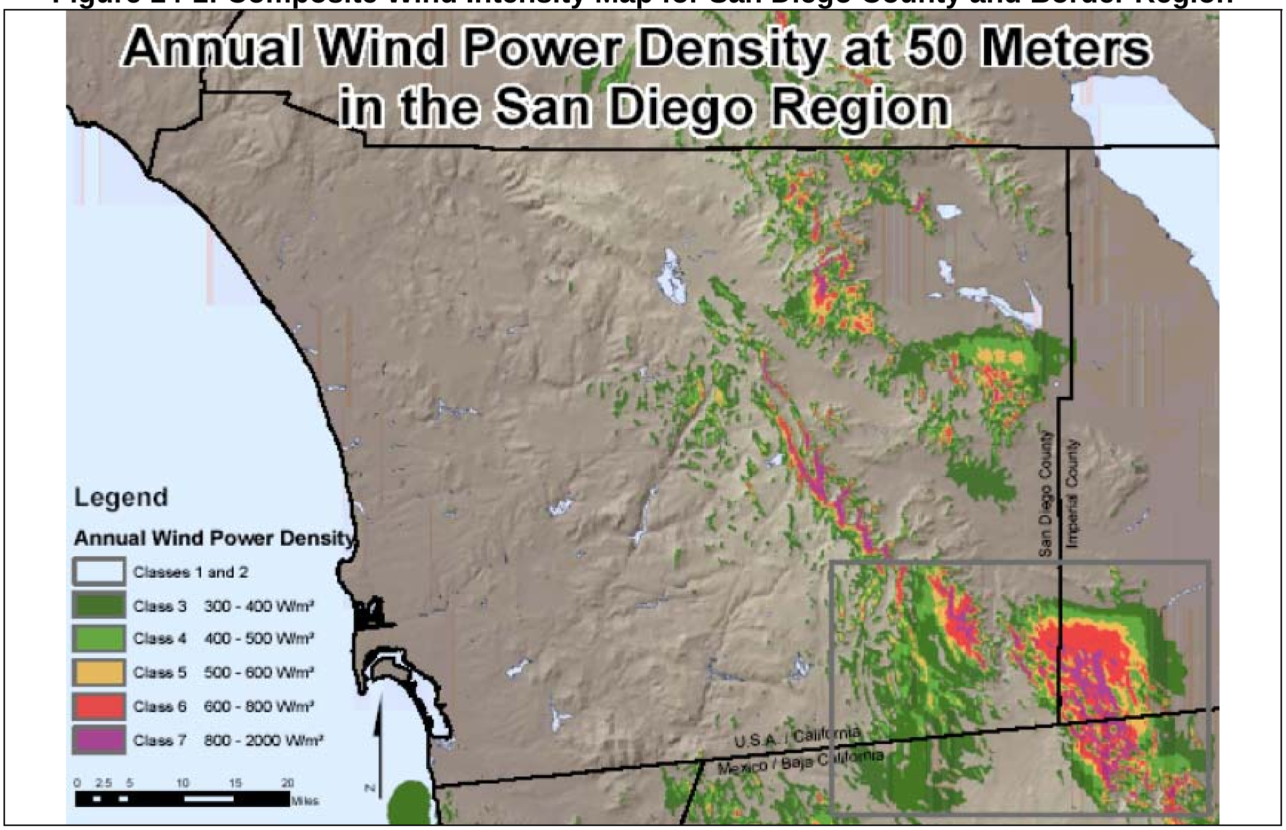
ACSR: aluminum conductor steel reinforced (conventional); ACCR: aluminum conductor composite reinforced

14. Utilizing the Wind Resource – What Are the Tradeoffs?

The regional wind resource is excellent, with a combined potential of 1,650 to 1,830 MW in eastern San Diego County and across the border in Baja California.[153] The high wind resource locations are shown in Figure 14-1. SDG&E has a power purchase agreement with a 50 MW wind farm located 60 miles east of San Diego. Fenosa, a Spanish firm, recently announced plans to develop a 500 MW wind farm just across the border in an area of Baja California called La Rumorosa. The power will be exported to California. Sempra Energy has announced the company has purchased co-development rights for 250 MW of wind power in La Rumorosa as well, and that this power will be imported along SDG&E's existing 500 kV Southwest Powerlink (Southwest Powerlink is the red line along the border in Figure 13-3a).[154]

Wind power is a fully commercial technology and is cost-effective, in the range of $0.05 to $0.07/kWh.[155] However, the regional wind resource is strongest is at night and in non-summer months when electricity demand is relatively low. The wind resource tends to be weakest on summer days, when demand is highest. The high value wind resource sites also tend to be located in areas of spectacular natural beauty that are among the last large regional undisturbed habitats of a number of threatened and endangered species. This means that locating large wind farms in San Diego County will be controversial unless there is a credible preliminary process, similar to the process described previously for renewable energy parks, which identifies selected areas that are suitable and other areas that should be off-limits to wind projects.

Figure 14-1: Composite Wind Intensity Map for San Diego County and Border Region



Wind power is considerably less capital intensive than PV on a MW basis. The inclusion of a significant amount of wind power to reach the 50 percent GHG reduction target by 2020 would result in lower cost to reach the goal than a strategy based exclusively on PV. In addition to the 500 MW Fenosa project just over the border, wind developers have requested transmission access for over 800 MW of wind projects in eastern San Diego County. This is a total of approximately 1,300 MW of wind capacity. If half this wind capacity gets built to serve the San Diego area, approximately 600 MW, this new wind energy will provide about 10 percent of the San Diego region's energy needs in 2020 and about 20 percent of the targeted GHG reduction.

This quantity of wind power would equal the annual energy output of approximately 1,000 MW of PV capacity.[156]

However, no peak power demand contribution can be assigned to the regional wind resource. As noted, the wind trends to be strongest in evening hours and non-summer months. Effective energy storage would be necessary for wind power to reliably contribute to meeting peak power demand. Practical solutions to this challenge are: 1) pumped storage between reservoirs of different elevations in the county, 2) utility-scale battery storage with sodium-sulfur batteries, or 3) the advent of large numbers of plug-in hybrid vehicles that would allow wind energy feeding into the grid at night to charge vehicles. These vehicles would be plugged into the grid during the day when the owner is at work and would be available to feed back into the grid to meet rising demand during the day. These energy storage options are discussed in more detail in Section 15.

15. Energy Storage – Maximizing Renewable Energy Benefits

Energy storage systems allow intermittent renewable energy to be stored and used during periods of peak demand and highest electricity rates. Energy storage also allows work to be done during periods of low demand and low electricity prices. One example is the production of chilled water or ice for air conditioning systems in the evening for use during the peak demand period the following day, to reduce peak energy demand and avoid paying peak electricity prices. These systems are briefly described in the following paragraphs.

15.1 Battery storage for fixed rooftop PV

The electricity production from fixed rooftop PV systems typically declines by 3 pm. Yet the peak demand generally occurs in the 3 pm to 6 pm period. Therefore, only a portion of the PV system's capacity is available during the period of greatest demand. However, by adding a modest amount of battery storage to the system, 2 to 3 hours, the PV system can consistently supply power at or near its rated capacity during the afternoon peak. SCE is currently conducting a demonstration test of rooftop PV systems equipped with Gaia Power Tower energy management/battery storage systems operating as peaking power systems.[157] Adequate battery storage makes PV a much more valuable contributor to meeting peak demand than a fixed system with no battery storage.

Battery storage systems built with PV systems are eligible for the same tax credits as the PV systems.[158] These battery systems represent dependable power that can be dispatched by the utility during periods of peak demand and recharged at night when demand and prices are low. Adding limited battery storage to PV systems is today's off-the-shelf equivalent to what the plug-in hybrid automobile may be one day in the future. SDG&E is currently proposing a critical peak rate of $1.20/kWh. Battery storage will rapidly pay back in a dynamic pricing environment where battery power receives a critical peak price premium.

15.2 Large-scale utility battery storage

The Japanese are investing heavily in high-temperature, sodium-sulfur batteries for utility load-leveling applications. Approximately 150 MW of utility peak-shaving batteries are in service in Japan. American Electric Power, whose subsidiaries include electric utilities in the Indiana, Ohio, West Virginia area, is planning to install 35 MW of peak shaving sodium-sulfur batteries by 2017. Large-scale battery storage options are discussed in detail in **Attachment L**.

15.3 Thermal energy storage for air conditioning systems

Air conditioning systems that include thermal energy storage dramatically reduce the peak electrical demand of these systems. As noted above, thermal energy storage, in the form of cold water or ice, also allows work to be done during periods of low demand. This reduces peak energy demand and minimizes peak electricity prices paid by the owner. **Attachment H** includes a pair of thermal energy storage diagrams that explain how chilled water and ice thermal energy storage systems work.

15.4 Pumped hydroelectric storage for wind power

San Diego has one major pumped storage project, the Lake Olivenhain-Lake Hodges 40 MW project. Lake Olivehain is located at a significantly higher elevation than Lake Hodges. Water will be pumped from Lake Hodges to Lake Olivenhain during periods of low electricity demand, generally at nighttime, and sent from Lake Olivenhain to Lake Hodges by gravity to drive a hydroelectric turbine during periods of high electricity demand. A description of this project is provided in **Attachment M**.

15.5 Plug-in hybrid cars as peaking power plants

Plug-in hybrids could also fill the role of peaking power plants during periods of high demand. Battery-powered cars would serve as storage for energy generated in the evening, a period of relatively low demand and low electricity prices, and would discharge the power at peak demand times from a two-way electrical connection in the parking garage.

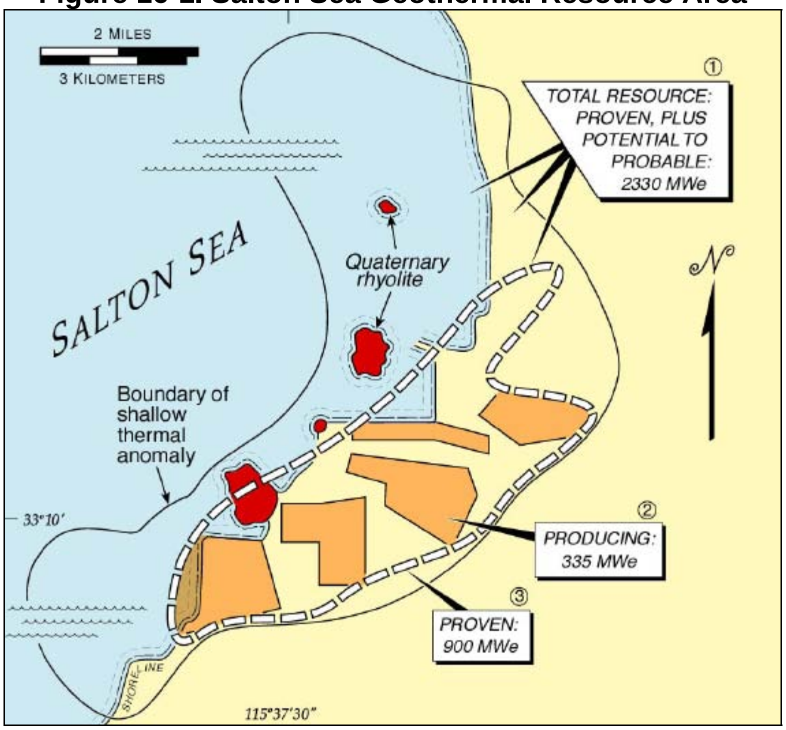
Google and PG&E will test six Toyota Prius and Ford Escape hybrid vehicles modified to run partly on electricity from the power grid.[159] One vehicle has been modified to send electricity back to PG&E. This test takes the hybrid a step further by using extra batteries to hold spare energy. PG&E will send wireless signals to the car while it is parked and plugged-in to determine its state of charge. PG&E can then recharge the batteries or draw out power. If there were thousands of such vehicles connected to the grid, the utility could store power produced in slack hours until it was needed at peak times.

The South Coast Air Quality Management District, which covers the entire greater Los Angeles-Long Beach-Riverside areas, is recommending the deployment of 100,000 plug-in hybrids by 2014 and up to 1,000,000 by 2020 in its 2007 Air Quality Management Plan.[160]

16. Geothermal Power – Is It Sustainable?

The geothermal resource in Imperial County is also significant, with a near-term potential of 800 MW.[161] Approximately 400 MW of geothermal power is already in production in Imperial County. The primary geothermal resource is located at the south end of the Salton Sea. See Figure 16-1. A major advantage of geothermal power is that it is available 24 hours a day, 7 days a week, in contrast to intermittent solar and wind resources. The cost of power production is also relatively low, in the range of $0.05 to $0.07/kwh.[162] However, the geothermal fluid in Imperial County is very high in solid content, approximately 20 percent, and these solids contain a high concentration of metals. The principal geothermal developer in Imperial County, CalEnergy, briefly experimented with refining zinc from the geothermal solids several years ago. Low zinc commodity prices made the zinc refining operation unprofitable and it was discontinued.

Figure 16-1. Salton Sea Geothermal Resource Area



Geothermal plants in the Imperial Valley are also large consumers of water. This water is primarily consumed in the evaporative cooling towers that are used to condense the geothermal steam after it passes through the power turbine. Much of the water used in the cooling tower is condensed geothermal reservoir fluid. This is geothermal fluid that does not get recycled back into the geothermal reservoir to maintain reservoir pressure. A concern with this approach is that as more and more geothermal plants are built in Imperial County, the pressure in the geothermal reservoir(s) may go into permanent decline and a potentially sustainable resource may become unsustainable.

This issue can be addressed by using a combination wet-dry cooling system that would reduce cooling tower water consumption by 80 to 90 percent. However, geothermal plants are very expensive to build. These plants will not be built to minimize the consumption of geothermal fluid in the cooling towers without state regulations that require minimum water use in geothermal plant cooling systems. It is unclear whether geothermal power development in Imperial County can be considered sustainable given the unknowns surrounding the impact of increasing consumptive use of geothermal fluid for evaporative cooling as more geothermal plants are built.

17. Rapid Expansion of Combined Heat and Power

Distributed generation systems are any power generators that generate power at the point of use. These systems can be renewable energy, such as rooftop PV, or highly efficient natural gas-fired "combined heat and power - CHP" systems. CHP have the lowest GHG footprint of any fossil fuel power generation system (639 lb CO_2 per MWh, compared to 819 lb CO_2 per MWh for combined cycle power plants and 1,170 lb CO_2 per MWh for peaking gas turbine power plants).[163]

Another benefit of CHP and other forms of distributed generation when compared to bulk transmission or central station power plant additions is reducing the consequences of single-point failures related to the outage of large transmission lines and power plants. Reducing exposure to system failures increases the overall security of local energy supply.

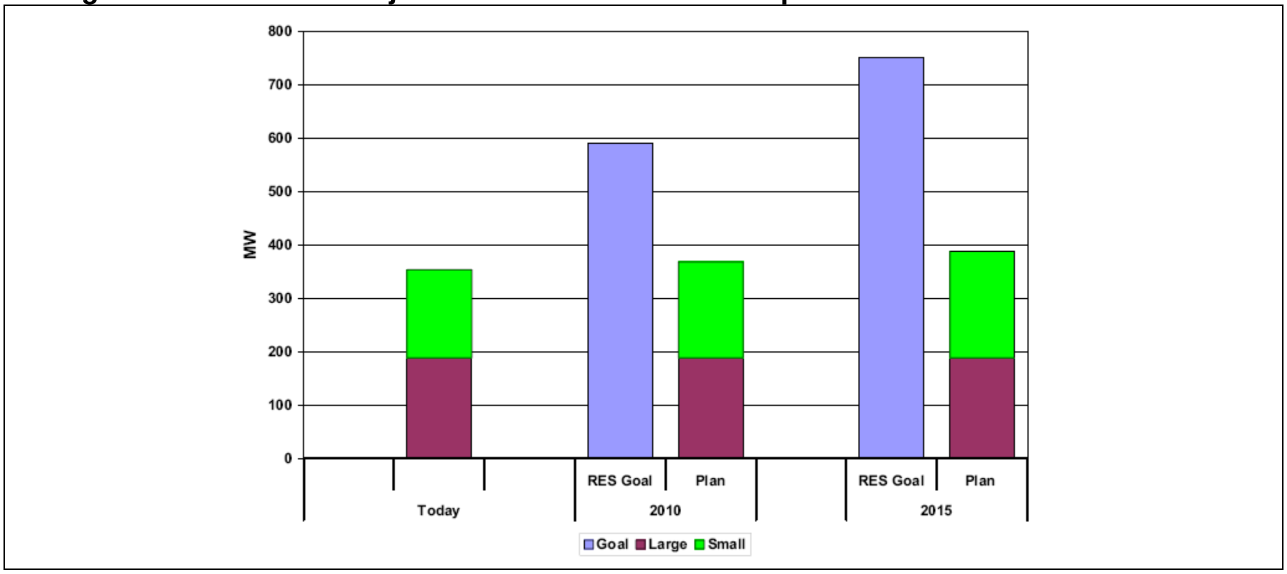
CHP facilities typically produce in the range of 1 to 20 MW of electric power. The hot exhaust gases from the combustion process, a small gas turbine or stationary reciprocating engine, are used to make steam or hot water for onsite use. The steam can be used for both heating and cooling. For example, steam can be used to drive a highly efficient centrifugal chiller to provide cooling in summer. That same steam can be used as a source of heat in winter, or by onsite processes that require steam.

Rapid expansion of CHP power generation is a priority goal in the *Energy Action Plan*. *Energy Action Plan II* states (p. 9): "*Develop tariffs and remove barriers to encourage the development of environmentally-sound combined heat and power resources and distributed generation projects*." The *Energy Action Plan* prioritizes CHP over large central power plants.

RES 2030 calls for 1,100 MW of CHP by 2020. There are currently less than 400 MW of CHP capacity in the San Diego region. Achieving the *RES 2030* target of 1,100 MW CHP capacity by 2020 means 700 MW of CHP must be added in the region. This is the equivalent of a "virtual" South Bay Power Plant replacement in terms of MW capacity, and would negate the need to construct another baseload power plant in the region.

The CEC "road map" for CHP development calls for CHP to provide 25 percent of peak load by 2020. SDG&E is projecting a peak load in 2016 of 5,060 MW. Twenty-five percent of 5,060 MW is 1,265 MW. Yet SDG&E projects almost no increase in CHP capacity over the next decade.[164] SDG&E estimates total large and small CHP at approximately 390 MW in 2015 as shown in Figure 17-1 (SDG&E projections are the green and purple bars labeled "Plan").[165] This is in contrast to the *RES 2030* goals of 590 MW of CHP by 2010 and 1,100 MW of CHP by 2020.

Figure 17-1. SDG&E Projected CHP Generation Compared to CHP Goals in RES 2030



The CEC indicates that significant energy policy changes will be necessary to accelerate the development of CHP in California. The March 2007 *Distributed Generation and Cogeneration Policy Roadmap for California* report prepared by CEC staff calls for ten more years of subsidies for distributed generation technologies.[166] These include incentive payments for CHP under the CEC's self-generation program. Making such policy changes, according to the report, could turn distributed generation from a nascent technology that makes 2.5 percent of peak power to a significant provider that meets 25 percent of the state's peak power needs by 2020.
Among the changes envisioned by the CEC to generate a quarter of the state's power from off-grid distributed generation are transparent dynamic rates for electricity. The report also recommends removing institutional barriers. For instance, distributed generation has been hampered by a lack of uniform rules and standards that could speed installation of equipment.

There are approximately 240 candidate sites for conventional CHP facilities in San Diego County.[167] These include large private employers, large city and county government centers, military bases, large hospitals, large hotel complexes, large shopping complexes, and large universities and colleges. Some of these sites already operate CHP plants, such as the University of California San Diego, San Diego State University, Children's Hospital, and Qualcomm.

A number of relatively large cogeneration (power and steam) plants are also located on military bases in the San Diego area and sell power to SDG&E. These plants are known as "qualifying facilities" and date from the 1980s. These plants "qualified" for a financially attractive electric rate, known as the Standard Offer 4 (SO-4) contract, which was developed in California to promote the construction of high efficiency cogeneration plants and renewable energy resources. The utilities were required to purchase all power generated by these facilities under the terms of the SO-4 contract.[168]

Utility tariffs more favorable to distributed generation are needed according to the March 2007 CEC policy roadmap. A favorable rate structure that accurately reflects the benefits of CHP is essential to expand the development of CHP in the San Diego area. SDG&E's proposed critical peak pricing tariff of $1.20/kWh is an example of a tariff that would greatly improve the economics of CHP.[169] This rate would apply for up to 126 hours per year. A CHP plant selling 2,000 kW to SDG&E for 126 hours at $1.20/kWh would receive $302,400 in revenue in return. The cost of fuel to provide this power would be in the range of $15,000 to $20,000.[170]

Applying a favorable tariff, like the PG&E A-6 tariff, to CHP in the San Diego region would also dramatically improve the financial attractiveness of CHP. The summer peak A-6 tariff is $0.319/kWh (see Table 10-2). The summer peak in SDG&E service territory is May 1 through September 30, from 11 am to 6 pm, a total of 1,071 hours per year. The total revenue from generating 2,000 kW at the A-6 rate for 1,071 hours is $683,000. The fuel cost to produce this power would be in the range of $150,000, leaving over $500,000 in net revenue. The revenue generated from power sales at the peak rate alone would nearly cover the financing of the CHP plant.[171]

SDG&E must also take all the excess power generated by CHP facilities to maximize the benefit of these plants to the region and to ensure the plants are operating at maximum efficiency. SDG&E recently established a precedent for taking excess power from CHP facilities when the company signed a contract in October 2006 to take excess power from the Children's Hospital CHP plant.

The SDG&E prohibition on CHP plants supplying power to adjacent buildings under different ownership creates an artificial barrier to CHP development in San Diego County as well. Similar facilities that individually are too small to support a dedicated conventional CHP plant, such as medium-sized hotels or commercial office buildings, are often clustered together. CHP would be significantly more cost-effective and fuel efficient if these "clusters" could be served by the same conventional CHP plant. This impediment must be addressed if the goal of adding 700 MW of CHP by 2020 is to be realized.

Smaller scale CHP options are now also available. The Sheraton Hotel and Marina on Harbor Island has a long-term agreement with Alliance Power for 1.5 MW stationary fuel cell power plant that supplies 70 percent of the hotel's electric power demand. The waste heat from the units is used to heat swimming pools and for domestic water heating. The plant consists of two fuel cells, a 1 MW unit and a second 0.5 MW unit. The 1 MW unit went online in December 2005, the 0.5 MW unit in mid-2006. A description of this project is provided in **Attachment N**.

Microturbines combined with absorption chillers are another example. United Technologies markets microturbine-absorption chiller packages under the trade name "PureComfort®." Systems are offered at 240 kW, 300 kW, and 360 kW. The hot exhaust gas is utilized in an absorption chiller/heater. The efficiency of this system can reach 90 percent. PureComfort® systems are installed at the Reagan Library in Simi Valley, California and the Ritz-Carlton Hotel in San Francisco.[172] The availability of such small CHP packages greatly expands the potential number of candidate CHP facilities in San Diego County.

18. Natural Gas-Fired Gas Turbine Generation – Where Does It Fit?

Natural gas-fired combined-cycle and peaking gas turbine capacity will be necessary to provide power at night and during periods of cloudy or inclement weather in 2020. These conventional generation assets will also be needed to provide reliability support as experience is gained in San Diego with greater and greater levels of intermittent renewable energy power. There will not be a need for new utility-scale base load generation, beyond the 542 MW Palomar Energy and 561 MW Otay Mesa combined-cycle projects, if the deployment of CHP and PV systems meet the capacity targets in *San Diego Smart Energy 2020*.

The CEC has determined that California's combined-cycle population operates with an average capacity factor between 53 and 61 percent on average.[173] SDG&E's two combined-cycle plants will be needed to provide power in the evenings in 2020. It is possible that the capacity factor of these two plants in 2020, as a result of operating in this "load following" pattern,[174] will be comparable to the average capacity factor of California combined-cycle plants today.

By 2020 the San Diego region will be exporting considerable amounts of power during the day when the PV systems and CHP plants are operating at or near capacity. The average daytime load is likely to fluctuate between 2,000 and 2,500 MW in 2020 under *San Diego Smart Energy 2020*, yet the combined capacity of the PV systems and CHP will be approximately 3,400 MW.[175] This means daytime power generation in the San Diego area from PV and CHP will exceed demand. This power will be exported to neighboring utility districts during these times on the existing transmission system. At night only the CHP plants will be operating, and output from these plants will 1,000 MW or less. Yet the average nighttime load is likely to be in the range of 1,500 to 2,000 MW. This will require that combined-cycle plants make up the difference.

The net effect of this diurnal cycling between PV and combined-cycle in 2020 will be that slightly more combined-cycle power is used in the San Diego region, approximately 500 GWh per year, than PV power is exported to neighboring utility territories.

19. Getting Maximum Benefit from the Existing Transmission Grid

19.1 Start from the Bottom Up: Modernize the Distribution Grid

The electricity distribution system is the relatively low voltage system, 12 kV and less, that directly serves neighborhoods and commercial areas. SDG&E'S electricity distribution system includes 264 distribution substations, 977 distribution circuits, 231,112 poles, 9,351 miles of underground system, 6,712 miles of overhead systems, and various other pieces of distribution equipment. SDG&E has an aging infrastructure problem across broad categories of transmission and distribution equipment.[176]

The single largest quantity of SDG&E transformers was installed in the 1950's. Many of these transformers are either approaching obsolescence or are obsolete due to excessive maintenance requirements, operational limitations, lack of spare parts, and deteriorating condition. Aging infrastructure affects not only substation transformer banks but also wood poles and underground cable. Approximately 30 percent of SDG&E's wood poles have been in service for at least 50 years, and approximately 48 percent have been in service for 40 years. Polymeric cables remain a large contributor to SDG&E's aging infrastructure problem, in particular cables installed prior to 1983. The pre-1983 vintage cables were manufactured with poorer manufacturing processes and much less quality controls and typically did not have a jacket. SDG&E continues to invest significant capital and resources to maintain these groups of cables.[177]

Aging SDG&E distribution infrastructure continues to demand more and more maintenance and repair resources. As the age of equipment increases the amount of maintenance necessary also increases. So does the probability of failure in-service. Aging equipment becomes obsolete due to wear, technology advancements, and lack of availability of replacement parts. A large amount of SDG&E'S distribution equipment is reaching the end of its useful life.

SDG&E has correctly identified that the weakness in the transmission system is at the distribution level, the interface with homes and businesses. The immediate need is a complete overhaul of the 12 kV distribution system. This is the appropriate time to invest in a revitalization of the SDG&E distribution system using "smart grid" technological innovations.

The smart grid concept was developed by the U.S. Department of Energy's Modern Grid Initiative. To address aging transmission and distribution infrastructure, the Modern Grid Initiative seeks to create a modern – or "smart" – grid that uses advanced sensing, communication, and control technologies to generate and distribute electricity more effectively, economically and securely. Smart grid integrates new innovative tools and technologies from generation, transmission and distribution to consumer appliances and equipment.

San Diego-based SAIC evaluated the benefits of implementing a smart grid in the San Diego area in 2006.[178] The benefits identified by SAIC include:

- Reduction in congestion cost.
- Reduced blackout probability.
- Reduction in forced outages/interruptions.
- Reduction in restoration time and reduced operations and maintenance.
- Reduction in peak demand.
- Other benefits due to self diagnosing and self healing.
- Increased integration of distributed generation resources and higher capacity utilization.
- Increased security and tolerance to attacks/natural disasters.
- Power quality, reliability, and system availability and capacity improvement due to improved power flow.
- Job creation and increased gross regional product.
- Increased capital investment efficiency due to tighter design limits and optimized use of
- grid assets.

- Tax savings for the utility from a depreciation increase.
- Environmental benefits gained by increased asset utilization.

If all thirteen smart grid improvement initiatives identified by SAIC for the San Diego region are implemented, the initiatives would generate $1.4 billion in utility system benefits and nearly $1.4 billion in customer benefits over 20 years.

19.2 Existing 230 kV and 500 kV Corridors: Low Cost Upgrades Buy Big Benefits

SDG&E has two major existing transmission import corridors. Each of these corridors can be upgraded economically to provide more reliability support to the SDG&E transmission system.

Five 230 kV lines, collectively known as "Path 44," provide north-south transmission from the San Onofre Nuclear Generating Station substation, on the property of Camp Pendleton Marine Corps Base, into the San Diego urban area. The emergency transmission capacity of Path 44 is 2,500 MW. Emergency capacity in this case means the capacity when the largest import transmission line into the San Diego area, the 500 kV Southwest Powerlink (SWPL) with a rated capacity of 1,900 MW, is temporarily out-of-service.

Path 44 rating plays a key role in determining SDG&E power reliability needs. The Utility Consumer's Action Network (UCAN) has proposed that SDG&E take the actions necessary to upgrade Path 44 to allow emergency import limit for Path 44 from 2,500 MW to 2,850 MW. This upgrade would reduce SDG&E's local power reliability needs by 350 MW. UCAN estimates $111 million would be necessary to upgrade the Path 44 import capability by 350 MW.[179]

SDG&E's east-west SWPL transmission line is rated at 1,900 MW, but is currently limited to 1,450 to 1,750 MW due to transformer emergency overload concerns at the Miguel substation. The Miguel substation is the western terminus of SWPL. It is located several miles to the southeast of San Diego. There are two 230 kV/500 kV transformers at the Miguel substation. SDG&E's concern is that the outage of one 230 kV/500 kV transformer at Miguel would cause the adjacent transformer to exceed its emergency rating. One simple method to avoid this risk is to plan in advance that, if imports are above the current import limit, which varies hourly between 1,450 MW and 1,750 MW, and one transformer fails, then the other transformer will automatically be shut down as well.

SDG&E forecasts that there will be 400 to 1,400 hours per year in the 2010 to 2020 period when power imports along SWPL to Miguel will be constrained if SPL is not built. Modifying Miguel substation transformer operations in response could save millions of dollars almost immediately. This would more than cover the implementation cost of a more complex transformer operating procedure. The cost of increasing the import limit across the Miguel transformers to 1,900 MW is essentially zero using this approach. UCAN also estimates that the incremental cost to increase Miguel outlet capacity to 2,100 MW would be between $4 and $35 million. This is a situation where significant incremental transmission benefits can be obtained for a low incremental cost.[180]

20. Staying On Track: Loading Order and Distributed Generation Policy Initiatives

The SANDAG Energy Working Group is actively promoting legislation that would: 1) direct the CPUC to refine its current utility ratebasing policies to better reflect and support the *Energy Action Plan* loading order, and 2) direct the CEC to continue incentives for CHP installations.[181] The September 20, 2007 decision in the CPUC energy efficiency proceeding has initiated the process of bringing utility financial incentives into alignment with the loading order.[182] Two bills currently moving through the Legislature, AB 1064 (Lieber), the Self Generator Incentive Program extension legislation and AB 1613 (Blakeslee), Waste Heat and Carbon Emissions Reduction Act, could impact the rate of CHP development in California if they are passed into law.

The concept of the loading order is not unique to California. This same approach, prioritizing a package of energy efficiency, demand response, and distributed renewable and CHP generation measures, is currently being advocated in Maryland by a coalition of clean energy developers, including Solar Turbines, as a cost-effective alternative to a proposed $1.8 billion transmission line. The proposed transmission line would import coal power to meet a projected demand growth of 1,800 MW. The Maryland case is addressed in this section.

20.1 Aligning Utility Incentives with Energy Action Plan

The Energy Working Group has recommended the passage of legislation directing the CPUC to open a new proceeding to review and refine its existing utility infrastructure ratebasing policies to better align its policies with the loading order in *Energy Action Plan II*. The loading order described in *Energy Action Plan II* is shown in Figure 20-1. The new legislation would direct the CPUC to develop appropriate new utility shareholder penalties and revenue opportunities for failing, meeting, or exceeding *Energy Action Plan II* loading order goals and targets.

Figure 20-1. Aligning Utility Financial Incentives with Loading Order

CA Resource Loading Order	Proposed Change
Energy Efficiency	Highest ROI
Demand Response	⇑
Renewables	Sliding Scale
Distributed Generation	⇓
Fossil-Fuel Power Plants and Related New Transmission	Lowest ROI

Current CPUC ratebasing policies provide utility shareholder incentives for the bottom of the loading order, utility-scale power plants and new transmission, but offers no shareholder revenue earning opportunities for energy efficiency, demand response, renewables, and distributed generation at the top of the loading order. This runs counter to state energy priorities and needs to be revisited by the CPUC.

The September 20, 2007 CPUC decision in the energy efficiency proceeding (R.06-04-010) has restored energy efficiency program performance-based shareholder penalties and rewards that were dropped by the CPUC in 2002. However, this proceeding is not considering any changes in current ratebasing policies, and would not address the other priorities listed in the loading order. The CPUC has not reviewed or refined its current utility ratebasing policies since 2003, the year the original *Energy Action Plan* was adopted.

The legislature and the CPUC must reorient the existing utility incentives if energy efficiency, renewable energy, and distributed generation are to be prioritized over the traditional utility steel-in-the-ground approach. The financial motivators need to be realigned so that utilities profit by supporting the *Energy Action Plan* loading order, and are penalized if they do not.

20.2 Extend Incentive Program for Clean Distributed Generation

In most parts of the U.S. and the world, CHP is recognized as an efficient and environmentally advantageous technology. Clean natural gas CHP:

- Achieves combined electric and thermal efficiencies from 60 to 90 percent.
- Avoids and or defers the need to build costly electric transmission and distribution infrastructure.
- Eliminates or reduces transmission and distribution losses, reduces or eliminates grid congestion.
- Significantly decreases GHG emissions relative to any other type of natural gas combustion.

Incentives for CHP are important to accelerate projects, to offset the many institutional and utility obstacles that are still present, and to help support industry investment in low emission technology. A 2005 CEC assessment of CHP concluded that continuation of the Self Generator Incentive Program would increase CHP by more than 40 percent over the next 15-year period, with natural gas engines and turbines accounting for an overwhelming share of the new capacity additions.

The current Self Generator Incentive Program expires on December 31, 2007. The proposed legislation would direct the CPUC in consultation with the CEC to administer a Self Generation Incentive Program for ultra-clean and low-emission fossil-fuel CHP technologies, and waste gas fueled generation, that would commence on January 1, 2008, and continue to January 1, 2012.

However AB 1064 (Lieber), the Self Generator Incentive Program extension legislation in the Assembly, no longer includes a continuation of incentives for conventional CHP. This CHP component was deleted in committee.[183] Starting January 1, 2008, only fuel cell and wind technology will be eligible for incentives in statute. Unless the incentives for conventional CHP are reincorporated in AB 1064, this legislation will not assist in accelerating the construction of CHP capacity in San Diego County.

AB 1613 (Blakeslee), Waste Heat and Carbon Emissions Reduction Act, would encourage the construction of CHP in California if it is passed into law. This legislation would establish that the conversion of waste heat to electricity or other useful energy application is an efficiency measure for purposes of the loading order. The objective of the legislation is to add 5,000 MW of new CHP by 2015 in California.[184] This bill is awaiting Governor Schwarzenegger's signature as of October 10, 2007.

20.3 Distributed Generation as Alternative to New Transmission – Maryland Case Study

The Maryland Public Service Commission is currently evaluating a proposed 290-mile transmission line that would import power from West Virginia to Maryland. A major justification for the line is a concern over transmission congestion as electricity demand increases over time. Maryland recently signed into law legislation to add 1,500 MW of solar energy over the next 15 years. A coalition of clean energy developers is advocating that the Commission undertake a thorough study of specific renewable energy, clean CHP, and demand management "smart grid" measures as an alternative to the proposed transmission line.[185]

The clean energy coalition asserts in its August 17, 2007 letter to the chairman of the Maryland Public Service Commission that:[186]

> *We believe that this accelerated, continuous development (of peak-coincident solar energy, high efficiency distributed generation, and "smart grid" technologies) could be achieved at a ratepayer cost less than the proposed $1.8 billion with significantly reduced delivery and financial risk as compared to a single massive transmission corridor. Further, these resources would bring low-emissions generation capability into Maryland. The choice is between expending ratepayer funding on low-risk, low-emissions distributed generation, or relying on a single, controversial, high risk project that will only enable the export of our energy dollars to produce air pollution upwind.*

The Maryland clean energy industry coalition letter is provided in **Attachment O**.

21. Accommodating Growth – New Construction Must Account for Its Own Energy Needs

New construction in San Diego must "carries its own weight" in terms of electric energy demand. This can be achieved by requiring that new construction meet most or all of its projected electric energy demand through use of rooftop PV. This does not mean that new construction will necessarily be burdened with additional costs. For example, the PV program described in this report would result in lower electricity costs than purchasing electricity from SDG&E.

Numerous home builders in the Central Valley are incorporating rooftop PV into all new home construction as a standard feature.[187] This should be a standard feature for new home construction in San Diego County as well. The energy demand of new and renovated buildings should also be minimized by requiring that cost-effective green building design principles be utilized. The affect of incorporating green building principles is dramatic. California's Attorney General Jerry Brown has specifically recommended that San Diego take these actions to more effectively address climate change.[188]

In it ongoing energy efficiency proceeding, the CPUC has issued a September 17, 2007 draft decision with three initiatives described as "essential": 1) all new residential construction in California will be zero net energy by 2020, 2) all new commercial construction in California will be zero net energy by 2030, and 3) the heating, ventilation, and air conditioning industry must be reshaped for maximum efficiency. The stated motivation for moving to zero net energy demand in new structures is the revolutionary impact of global warming on the global economy.[189]

22. Conclusions

1. Climate change is a critical problem and arguably the greatest single issue of our time. The *California Global Warming Solutions Act* of 2006, AB 32, mandates a 25 percent reduction in greenhouse gases by 2020 and an 80 percent reduction by 2050. Reaching these mandates will require a more rapid transition to renewable energy sources for power generation than is currently contemplated.

2. Domestic natural gas currently used in the San Diego region will be displaced by imported liquefied natural gas in 2009. Liquefied natural gas carries an additional 25 percent "lifecycle" greenhouse gas burden relative to domestic natural gas. This displacement will nullify the greenhouse gas reductions projected by SDG&E over the next decade. Accelerated deployment of energy efficiency measures and renewable energy technology would mean considerably less dependence on volatile natural gas prices and liquefied natural gas imports.

3. The San Diego region is projected to have approximately 4,600 MW of PV potential on commercial buildings, parking structures, and parking lots in 2010, as well as 2,800 MW

of technical potential on residential structures. The 2010 technical potential for PV is in the range of 7,400 MW. A major advantage of commercial and residential PV is the relative lack of siting controversies. Also, PV equipped with adequate (2- to 3-hour) battery storage would be a dependable energy resource during peak demand periods. 2,040 MW of PV capacity, equipped with sufficient battery support to reliably provide power at or near capacity during the 3 to 6 pm peak on hot summer days, would meet more than half of the San Diego area's peak power needs under most conditions in 2020.

4. A $1.5 billion PV incentive program would be sufficient to incentivize the construction of 2,040 MW of distributed PV in the San Diego area by 2020. The incentive program would be similar to the structure of SB1 and the California Solar Initiative, where an incentive pool of $3.35 billion is expected to add 3,000 MW of PV in California by 2017. A goal of SB1 and CSI is to reduce the cost of PV to the point where PV is cost-competitive with conventional natural gas-fired generation without incentives by 2016.

5. The expansion of rooftop commercial and residential PV systems and CHP projects is currently limited by: 1) the inability to sell excess power to SDG&E, and 2) the relatively low commercial electricity rates during peak demand periods that do not reflect the real value of the electricity.

6. The *Energy Action Plan* calls for a 20 percent reduction in energy consumption to be achieved in government and commercial buildings by 2015 compared to a 2003 baseline. The San Diego region's annual energy consumption over the last few years has been approximately 20,000 GWh. Setting a real 20 percent reduction in regional energy demand compared to the 2003 baseline year as the regional energy efficiency target would mean an absolute decline in energy demand of approximately 4,000 GWh, leaving a net total energy demand in 2020 of 16,000 GWh.

7. SDG&E peak demand in 2007 was 4,636 MW. Approximately 1,500 MW of this peak load was associated with residential and commercial building cooling systems. Yet little effort or money is currently being invested in reducing the demand of these cooling systems through utility energy efficiency incentive programs.

8. SDG&E will complete the installation of smart meters at all customer locations by 2011. SDG&E projects that these smart meters will reduce peak demand by 5 percent. Smart meters with thermostat control capability were demonstrated to reduce peak load by 27 percent during a three-year California test. The advent of smart meters also offers the potential to sequentially cycle a portion of the cooling systems drawing power from the grid. The duration of the cycling would be brief enough to avoid discomfort, yet would keep hundreds of MW of cooling system load off the power grid during periods of very high demand.

9. Central air conditioning units are the predominant residential cooling system. State-of-the-art central air conditioning units use as little as one-half the power of the "average" central air conditioning unit in the San Diego area. There is a similar gap in the energy efficiency of the typical commercial building cooling system in the San Diego area and

its potential performance with a cost-effective upgrade to variable speed motors and associated controls.

10. Lighting is an area where energy efficiency measures can have a dramatic impact. Compact fluorescent bulbs reduce energy demand by 75 percent relative to a standard incandescent bulb. Currently 10 to 20 percent of bulbs are compact fluorescent bulbs. New light emitting diode lighting technologies can also reduce lighting related demand even further.

11. Refrigeration has been a modest energy efficiency success story. The average energy efficiency of refrigerators in the San Diego area improved by 22 percent between 2000 and 2005. Federal "energy star" efficiency standards for refrigerators have been a factor. Consumer interest in energy efficiency has also been a factor in refrigerator purchasing decisions, supported by limited rebates offered by SDG&E.

12. Upgrading existing buildings to current Title 24 structural weatherization standards or beyond is cost-effective. The *Energy Action Plan* calls for all existing state buildings to be upgraded to meet rigorous "LEED" green building standards by 2015, and establishes the same goal for commercial buildings. SDG&E currently offers free home weatherization and energy efficient appliance replacement services to low-income customers via its "direct assistance" program. Expanding this program to include all cost-effective energy efficiency upgrades regardless of consumer income level is necessary to fully realize regional energy efficiency opportunities.

13. Rapid expansion of CHP is a priority goal in the *Energy Action Plan* and RES 2030. The *Energy Action Plan* prioritizes CHP over large central power plants. There is currently less than 400 MW of CHP capacity in the San Diego area. 700 MW of CHP must be added to meet the RES 2030 target of 1,100 MW of CHP capacity by 2020.

14. There will not be a need for additional utility-scale base load generation, beyond the 542 MW Palomar Energy and 561 MW Otay Mesa combined-cycle projects, if the deployment of CHP meets *San Diego Smart Energy 2020* targets. If *San Diego Smart Energy 2020* milestones and targets are met, there will also be no need to add additional peaking gas turbine capacity.